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Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status

Intermediate/Three-Phase Systems

R. L. Das
J. W. Klein
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September 15, 1982

Prepared for
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Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy through an agreement with the National Aeronautics and Space Administration.

Work conducted by the Jet Propulsion Laboratory through NASA Task RD-152, Amendment 325, and was sponsored by the Sandia National Laboratories, Order No. P.O. 68-4728, for the U.S. Department of Energy.

ABSTRACT

This document is a continuation of a previous study funded by the Department of Energy on the Utility Interface Issues of Category I, Distributed Photovoltaic Systems, Report No. DOE/ET-20356-3. That work looked at single-phase, residental PV systems in detail. The study herein details the interface issues associated with intermediate (30-kW to 1-MW, three-phase) installations.

For ease of reading, this report is a stand-alone document with abbreviated discussion on those issues covered previously and detailed discussions on new topics. The asterisks in Table 1-2 denote those issues where features additional to DOE/ET-20356-3 are discussed in this report. The section dealing with System Unbalance, covered in the previous document, is not considered for intermediate installations since three-phase inverters are used. There is a small concern about the unbalanced voltage condition for the inverter but the authors assume that this condition will be sensed and the PV source disconnected, if excessive unbalance occurred.

It is anticipated that a follow-on report on the interface issues for central station PV generators (over 5 MW) will be written shortly.

FOREWORD

This document is a continuation of a previous study funded by the Department of Energy on the Utility Interface Issues of Category I, Distributed Photovoltaic Systems, Report No. DOE/ET-20356-3. That work looked at single-phase, residental PV systems in detail. The study herein details the interface issues associated with intermediate (30-kW to 1-MW, three-phase) installations.

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It is anticipated that a follow-on report on the interface issues for central station PV generators (over 5 MW) will be written shortly.

ACKNOWLEDGEMENTS

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Finally, thanks are due to Kolynn Younger for the typing of this document.

GLOSSARY

AGC	Automatic Generation Control
ANSI	American National Standards Institute
APPA	American Public Power Association
CFLC	Current Fed Line-Commutated Inverter
DOE	U. S. Department of Energy
DSG	Dispersed Storage and Generation
DSW	Distributed Solar and Wind
FERC	Federal Energy Regulatory Commission
GIS	Gas Insulated Substation
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
JPL	Jet Propulsion Laboratory
LLP	Large Local Penetration
kWh	Kilowatt hour
LSP	Large System Penetration
METAP	McGraw-Edison Transient Analysis Program
MIT/LL	Massachusetts Institute of Technology/Lincoln Laboratory
NBS	National Bureau of Standards
NEC	National Electrical Code
NESC	National Electric Safety Code
NFPA	National Fire Protection Association
ORNL	Oak Ridge National Laboratory
PCS	Power Conditioning Subsystem
PCU	Power Conditioning Unit
PF	Power Factor
PG&E	Pacific Gas & Electric
PUC	Public Utilities Commission
PV	Photovoltaic
QF	Qualifying Facility
RFP	Request for Proposal
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SERI	Solar Energy Reseach Institute
T&D	Transmission and Distribution
TNA	Transient Network Analyzer
TOD	Time of Day
TR	Technology Readiness
TVA	Tennessee Valley Authority
UL	Underwriters Laboratory
VAR	Volt-Amp Reactive
VFFC	Voltage Fed Force Commutated Inverter

CONTENTS

SECTION I

INTRODUCTION AND SUMMARY

A. BACKGROUND

Photovoltaic (PV) power generation has a great potential for providing a substantial portion of this country's future energy needs. It provides an inexhaustible and relatively clean energy source. The technical feasibility of PV power generation has been a demonstrated fact for many years, but costs of systems currently being produced have confined their use to small-scale, remote applications. It has been determined that to achieve significant fuel displacement, the PV systems must be connected to the utility power system.

However, for the utilities to consider augmenting their conventional generating capacity with substantial PV generation and the customers (or utility) to accept it, many customer utility interface technical issues must be resolved. These issues arise from the following major differences between PV and conventional generation:

(1) PV generation is stochastic in nature while conventional generation is deterministic (barring forced outages of conventional generating units).

(2) Solar cells generate dc power; conventional units generate ac power.

(3) In distributed PV systems, the PV sources will be connected to the distribution system. Thus, the functional requirements of the distribution system will have to change with a consequent impact on its design and operation.

So far, limited engineering effort has been expended to identify and resolve the critical issues related to the satisfactory integration of PV generation sources into the utility power system. This may be due partly to the fact that, at present, the total PV kilowatt capacity connected to the grid is quite limited, and none of these operating systems are considered fully developed from the standpoint of the utility. There is a real possibility that, in the future, PV systems will have to be integrated into utility systems with other types of Dispersed Storage and Generation such as fuel cells, batteries, and wind generators. This makes the problems of PV integration even more complex. The guiding principle to be followed is that the integration should not result in any adverse impact to the utility, PV owner, or other customers.

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Three categories of the photovoltaic power generators have been defined as shown in Table 1-1.

Table 1-1. PCS Categories

Category	Loads	Power Rating	Interconnection Voltage
Residential	Residential	2-10 kW	120/240 V, 1-ph
Intermediate	Commercial Industrial Agricultural	30 kW to 1 MW	208Y 120 480Y/277
Central	Utility Grid	5 MW minimum	4 kV and above

The integration of distributed PV systems in a future utility is shown in Figure 1-1. The Power Conditioning Subsystem (PCS) consists of the dc/ac inverter and its controls, filters, protective equipment and associated switching. The other DSG systems connected to the distribution system may be fuel cells, batteries, wind generators, and other PV systems.

Some of the key questions that can arise from such an integration are:

(1) What quality of the power (waveform distortion, power factor, etc.) produced by PV systems is acceptable to the utility?

(2) What are the Power Conditioning Subsystem requirements so that this quality can be achieved economically, safely, and reliably?

(3) How should the Power Conditioning Subsystem be controlled so that it operates in a stable mode and ensures optimal power transfer between the PV array and the utility power system?

(4) How should the transmission or the distribution system be modified to make the parallel operation of the PV generation sources possible? Can any of the power quality requirements be achieved by modifying the transmission or distribution system, rather than by placing uneconomical constraints on the Power Conditioning Subsystem?

(5) How do other DSGs connected to the distribution system impact the design of the Power Conditioning Subsystem?

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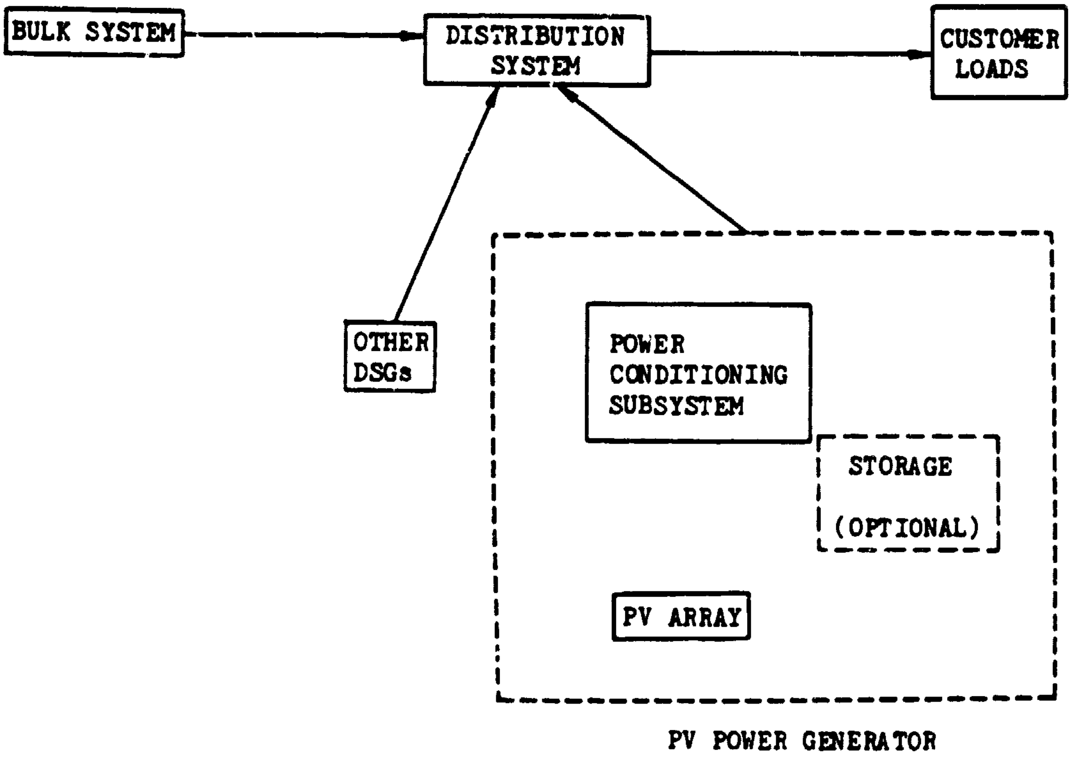

Figure 1-1. Interaction of the Various Systems in a Future Utility

B. POWER CONDITIONING SUBSYSTEM (PCS)

This document focuses on the interface issues between the intermediate-size PCS and the utility (Table 1-2, page 1-8). A companion document* detailed equivalent interface issues for residential systems.

For intermediate-size systems the generated power is 60 Hz, three-phase power. The interconnection of the Power Conditioning Subsystem and the utility occurs at the distribution level.

So far, all presently commissioned installations interconnect at the secondary distribution level, where the three-phase voltages are 208 V, 240 V, or 480 V. They supply power to selected publicly-owned facilities. The power outputs range from 50 kW to 300 kW. In the future, the above level may extend into the MW range and the generation may be used to supply power to industrial, commercial and agricultural customers.

Thyristors and transistors are utilized for power conversion. Single or multiple three-phase bridge configurations are employed.

Of the various types of dc to ac conversion alternatives available, two configurations are commonly used today.

Current Fed Line-Commutated (CFLC) inverters switch a dc current (using utility voltage for commutation) so that the resulting output is an alternating waveform. The voltage at the output terminals is then a function of the driving point impedance looking into the terminals of the utility. In other words, such a inverter behaves as a current source.

Voltage Fed Force-Commutated (VFFC) inverters (also known as self-commutated inverters) switch a dc voltage (using their internal 'clocks' for timing purposes) so that the output represents an ac voltage waveform. The current waveform is then a function of the driving point impedance into the terminals of the utility at the inverter. Such a inverter behaves as a voltage source.

Solid-State inverter type generators differ from synchronous generators in two important aspects:

(1) The inverter output is current limited to a level compatible with the ratings of power semiconductors. The fault currents drawn may be too small to clear isolated distribution system faults.

*__Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status__, M. Hassan, J. Klein, September 1981 DOE/ET-20356-3.

(2) An additional source of reactive power must be provided if line commutated inverters are deployed. Reactive power can be supplied by utility or customer owned synchronous machines or capacitor banks.

C. TASK OBJECTIVES

There are major issues related to the integration of PV generation into the utility systems that need resolution. These issues will have important bearing on PV systems development and the utility distribution system design. As such, they can seriously impact the U.S. Department of Energy's (DOE) long-range cost and performance goals and thus impact the acceptance and inclusion of PV generation by the utilities and customers.

The objectives of this study were to:

(1) Define the various problems related to the integration of distributed three-phase PV generation into the utility systems and describe their impacts.

(2) Study all the available literature on the subject including:

(a) Work managed and performed by the various national labs such as Sandia.

(b) Work sponsored by the DOE Office of Electric Energy Systems (EES) and other DOE offices on new energy source integration (i.e., DOE/PV, DOE/WIND, etc.).

(c) IEEE guidelines and/or standards.

(d) EPRI-sponsored research.

(e) European utility guidelines and/or standards.

(f) Research reported in IEEE/IEE journals, etc.

(g) Publications generated by utilities.

(3) Apply the findings of the literature search to the problems defined above under (1) and determine if satisfactory solutions exist.

(4) Establish expectations for current studies and research.

(5) Identify further work required in resolving intermediate issues based on an assessment of the current status of the various issues.

This task emphasizes technical issues concerning intermediate-size systems with no dedicated electrical storage. Although central station PV systems are not specifically addressed, some of the issues raised here do apply to them also. However, analysis of such issues is beyond the scope of the current study. They will be examined in a future task.

D. TASK ARRANGEMENTS

The various major issues which were identified during this task are as follows:

(1) Protection.

(2) Stability.

(3) Voltage regulation and reactive power requirements.

(4) Harmonics.

(5) Metering.

(6) Safety and codes.

(7) Operations.

(8) Distribution system planning and design.

As will be explained later, some of these issues had to be subdivided still further to better define their impacts.

In this report, each major issue is discussed in an individual section. Each issue is assigned a proper definition and the risks posed to the Photovoltaics Program are described. Also, their scope and impact are briefly discussed. A brief review of all the relevant references revealed by an exhaustive literature search is presented for each section. A compilation of these references appears in Appendix A. Any guidelines or standards available on the various issues are also discussed. Other references which are only marginally useful for the present study are listed in Appendix B. Based on the literature search, the current and future status of the various issues are clearly indicated. The projections of future status are based on the premise that the currently planned or proposed DOE studies take place as scheduled. Finally, a plan of action for timely resolution for most of the issues is recommended.

This study also found that many organizations are studying various aspects of interface requirements for dispersed generators. A list of such organizations is given in Appendix C. It is recognized that this list is not complete. The authors would appreciate knowledge of other organizations involved in such studies.

E. CONCLUSIONS

A significant amount of information has been derived on the various issues which may arise from the integration of distributed PV systems into utility power systems. Although many isolated efforts to resolve the various issues have been identified, most of the issues remain unresolved. The added uncertainty concerning long-range Research and Development funding for PV implies that the conclusions given in this report on the future status of the various issues may be overly optimistic.

The literature review yielded facts about the status of identified issues, summarized in Table 1-2. The scale is from "0" to "10," resolved issues being "10" while issues with little information available are "0". The uncertainty of the Federal PV budget precludes any effort to state the future status of these issues. However, analysis of DOE future activities proposed before the budget revisions appear in the body of this report. The table also indicates the impact of each issue on various levels of penetration. These levels are defined below.

1. Technology Entry (TE)

For the purposes of this study, Technology Entry (TE) is defined as the successful installation of one PV array connected to a utility system, i.e., the emergence of the technology from the experimental step into operating utility systems.

2. Large Local Penetration (LLP)

This is defined as a level of penetration of PV sources on a distribution system feeder when the total PV output is around 10% of the feeder load (which could possibly be the case of a Category II installation of moderate size on a small feeder).

3. Large System Penetration (LSP)

This is defined as a level of penetration of PV sources on any utility system when the total PV output is around 10% of the system load.

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Table 1-2. Summary of the Present Status of the Various Issues for Category II*

Issue	Present Status	Impact
PCS Overvoltage Protection	9	Technology Entry (TE)
System Overvoltage Protection	5	
PCS Overcurrent and Other Protection	8	
PCS Other Protection	2	
Source Stability**	2	
Voltage Regulation	3	
Harmonics**	4	
Safety and Code Requirements	3	
Metering	3	
Harmonics (resonances)**	3	Large Local Penetration (LLP)
Utility System Overcurrent and Other Protection	3	
Distribution System Stability**	0	
Distribution System Planning	3	
Bulk System Stability	3	Large System Penetration (LSP)
System Operations**	1	

*Although every effort was made to uncover all the relevant literature, it is quite possible that some useful material was overlooked. If so, any pertinent information may be forwarded to the authors for inclusion in future work.

**Indicates those sections where additional issues, not previously presented in DOE/ET-20356-3, are covered in this document.

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F. RECOMMENDATIONS

Detailed recommendations are provided for a timely resolution of most unresolved issues. In most cases, they involve field measurements, laboratory testing, model and software development and extensive simulation. Due to the possibility of having many different designs of PCSs available for PV applications, the models should be developed for the various generic types of PCSs, such as line-commutated, self-commutated, high-frequency links, etc.

Although it is not specifically described in the recommendations, the results obtained through simulation and analysis should be verified in the field, if possible. The detailed planning for the full set of activities, including field verification, is beyond the scope of this study.

SECTION II

PROTECTION

A. INTRODUCTION

This section describes protection of the utility system and the Power Conditioning Subsystem (PCS) against varic s abnormal system operating conditions which could originate either in the utility system or the PV system itself.

Protection of the operating system is commonly achieved by shutting down the PCS and turning off the main circuit breaker, which links the PCS and utility. Shutdown can be initiated automatically or manually.

In some cases, however, such as overloading of the PCS, the protection is achieved by automatic readjustment of the power flow, rather than by initiation of a shutdown.

The issue of protection can be further divided into the categories shown in Figure 2-1.

B. POWER CONDITIONING SUBSYSTEM PROTECTION AGAINST INTERNAL FAULTS

1. Definition

Internal faults within the PCS are caused by failures in the PCS logic.

2. Risk

PCS logic malfunction can lead to a loss of synchronization, (see Section II. c. 4). Loss of synchronization could cause substantial damage to the PCS and possibly to the utility equipment.

3. Discussion

The inverter and utility must run in a synchronous manner. This means the phase rotation of the PCS and utility voltage must be the same, the two systems must be in phase, and the level of the PCS should match the utility voltage level. Synchronism is maintained by means of the PCS logic and failure of the logic may cause loss of synchronization.

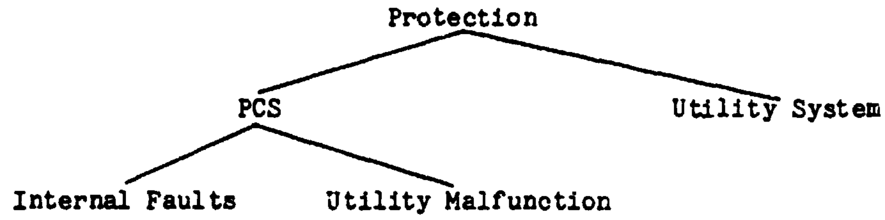

Figure 2-1. Protection Categories

C. POWER CONDITIONING SUBSYSTEM PROTECTION AGAINST UTILITY MALFUNCTIONS

1. Definition

The PCS must be protected against utility malfunctions, such as:

- o Transient overvoltages.
- o Utility failure (complete, partial or temporary).
- o Loss of synchronization (abnormal phase or frequency).

2. Transient Overvoltages

a. Risk. If voltage surges are allowed to enter the PCS without suppression, they could damage the components of the subsystem. The electronic components would be the most susceptible to damage due to their lower surge-withstand levels.

b. Discussion. Because the PCS is directly connected to the utility system, it is exposed to the transient overvoltages (or surges) occuring from time to time on the utility system. The transient overvoltages could be either of atmospheric or systemic origin. A prime example of the former is a lightning strike, which can cause overvoltages of very short duration (to the order of microseconds). The magnitude of the overvoltage is dependent upon the lightning strike, the point of impact, and the system characteristics. Some examples of transients originating within the system are switching surges and restrikes in switches and circuit-breakers.

The magnitude of these transient overvoltages, even though a system dependent parameter, can vary from a few times larger than

nominal (2) per unit* for switching surges to many times larger than nominal (10) per unit for lightning surges. Electronic components used in power conditioning systems such as transistors, SCRs, diodes, etc., will be more susceptible to damage by these voltage surges than conventional power system components such as transformers, cables, switchgear, etc. It is not unusual to specify surge-withstand voltage levels as high as 10 to 20 times the normal voltage rating for these conventional components. However, to achieve the same withstand level for electronic components is not practical. It is imperative, therefore, to provide proper surge protection so that the exposure voltage is limited to a safe value.

3. Resonant Overvoltage

a. Risk. These overvoltages could be of great enough magnitude to seriously damage power system components such as thyristors capacitors, etc.

b. Discussion. Overvoltages may be generated by resonances between the PCS output capacitors that are used for the purpose of filtering or power factor correction, and utility line inductances.

For the purpose of the analysis here, only ideal sources will be assumed. However, the ramifications of any impedances associated with these sources will also be discussed.

Figure 2-2 shows an ideal voltage source (self-commutated inverter) connected to a power system represented by a lumped inductance L and shunt capacitance C. The voltage source V_s is expected to be made up of many harmonic frequencies.

Under steady-state conditions, the voltage across the capacitance is given by:

$$|V_C| = |V_S| \frac{X_C}{X_C - X_L}$$

where

$|V_S|$ = magnitude of source voltage

$|V_C|$ = magnitude of voltage across capacitance

* Magnitude of "x" is "x" in per unit times the rated line-to-line voltage.

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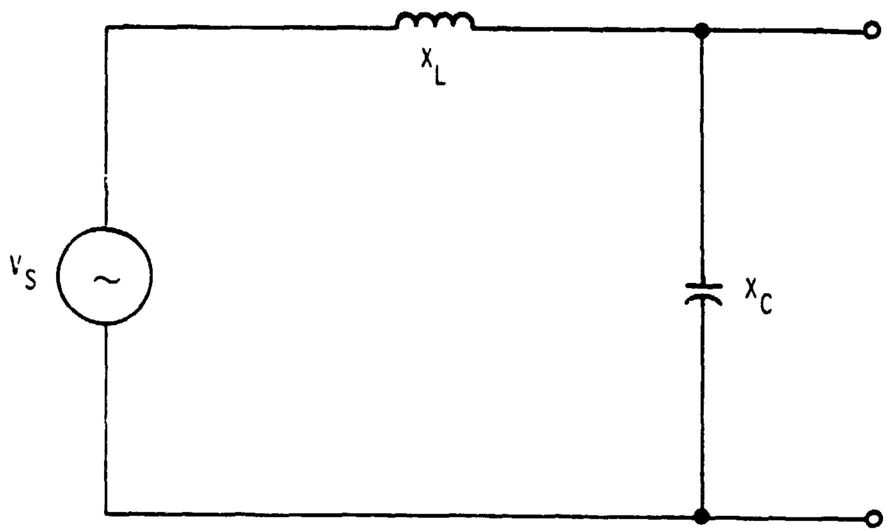

Figure 2-2. An Approximate Lumped Representation of a Power System

X_L = inductive reactance

X_C = capacitive reactance

for any frequency of interest.

At resonant frequency, $X_C = X_L$, and thus the voltage across the capacitance can theoretically go to infinity. However, because of damping associated with the source and system resistances, the voltage will be finite but possibly large in magnitude. Thus, to predict this magnitude, it is important to know of this resistance quite accurately.

Resonances can also occur if a current source inverter is employed. In such a case, resonances between parallel elements of the system will be of concern rather than the series resonances illustrated above.

Obviously, this is a very simplified analysis of an approximate representation of the power system. Its sole purpose is to give an insight to the problems of overvoltage which could occur from the interaction of the PV sources with the utility power system.

4. Utility Failure

a. <u>Risk.</u> Continued fault feeding by the PV source could cause the temporary interruptions of service to become permanent, resulting in prolonged interruption of service to a large part of the system. Improper coordination of the PCS protection with the rest of the utility system could result in substantial damage to the PCS.

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b. Discussion. In overhead distribution systems, initially a large percentage of the system faults are temporary (such as a tree limb falling on a line, arcing insulators, etc.). According to available statistics, 50 to 80% of the faults (both bolted and resistive faults) that occur on a system are temporary. Temporary faults are cleared by opening a recloser or a reclosing circuit-breaker to de-energize the circuit for a long enough time to let the fault clear by itself (such as an arc to extinguish). The recloser then automatically closes and if the fault still persists, it opens again. This opening and closing sequence is repeated two to three times, depending upon the application. If the fault is still not cleared, the recloser is locked out in an open position and permanently disconnects the circuit until the fault is manually located and removed and the recloser is manually reset. A typical recloser operating sequence is depicted in Figure 2-3.

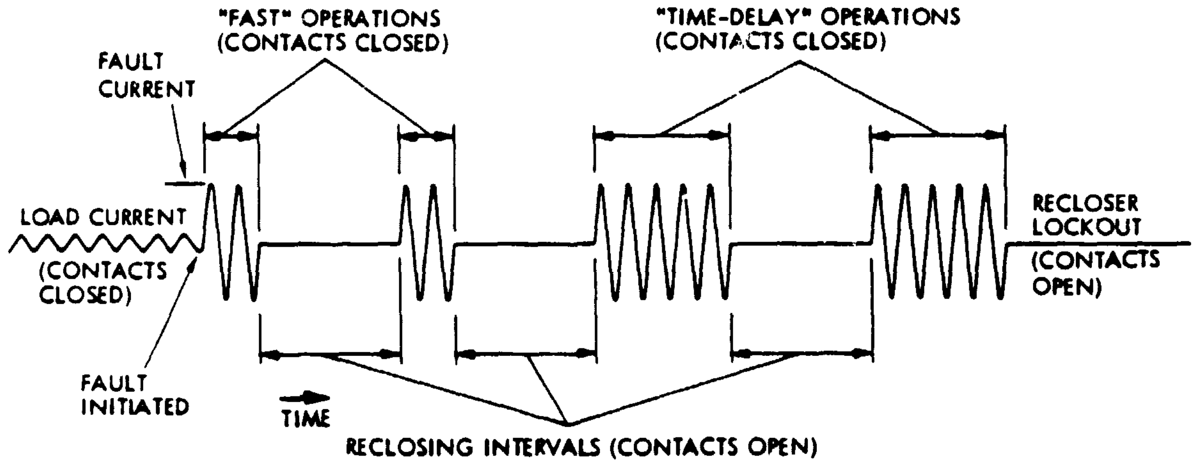

Figure 2-3. A Typical Recloser Operating Sequence

It is also important that the opening of the PV system circuit-breaker be properly time and current-coordinated with the utility protective system. The utilities should remain in charge of the installation of the relays required to achieve such coordination. Figures 2-4 and 2-5 show the instrumentation of such an interface, according to Ref. 10 (p. 2-10, 11) of the Guideline/Standards Section.

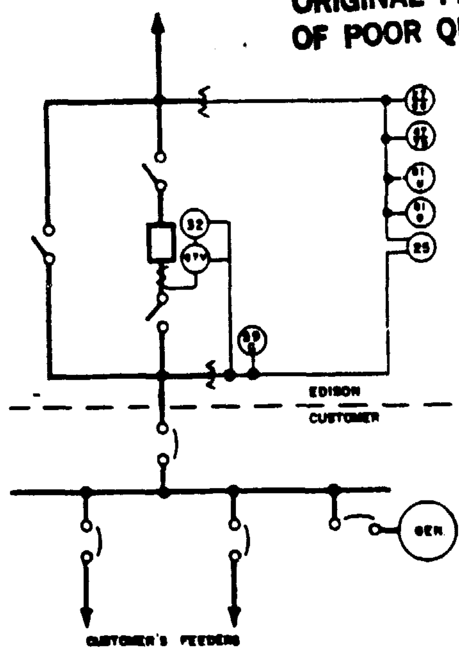

Figure 2-4. Interface Protection for Customer Installation of 200 kVA or Below, According to Southern California Edison

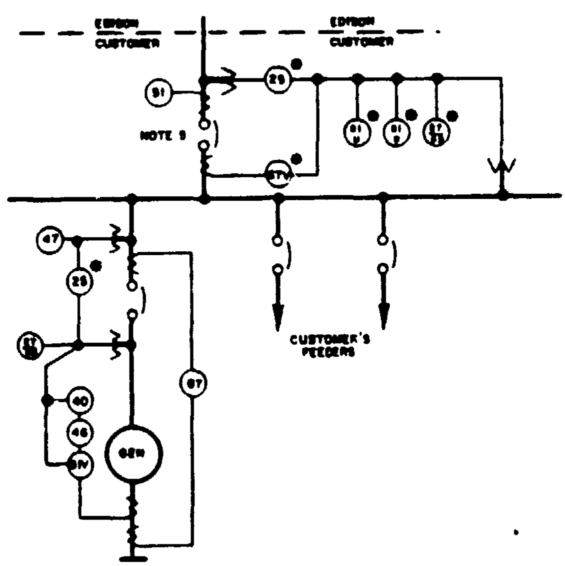

Figure 2-5. Interface Protection for Above 200 kVA Customer Installation According to Southern California Edison

5. Loss of Synchronization

a. Risk. Any interruption of utility service, even very short in time, may cause loss of synchronization. Loss of synchronization can cause a substantial damage to the PCS.

Synchronism between the PCS and the utility is defined as the matching of PCS voltage magnitude, phase, and frequency with the utility voltage magnitude, phase, and frequency. Thus, the loss of such synchronism involves the cases where voltage magnitude, phase, or frequencies do not match. Under such cases excessive currents can flow which might cause damage to the PCS. The simplified schematic below will demonstrate these facts:

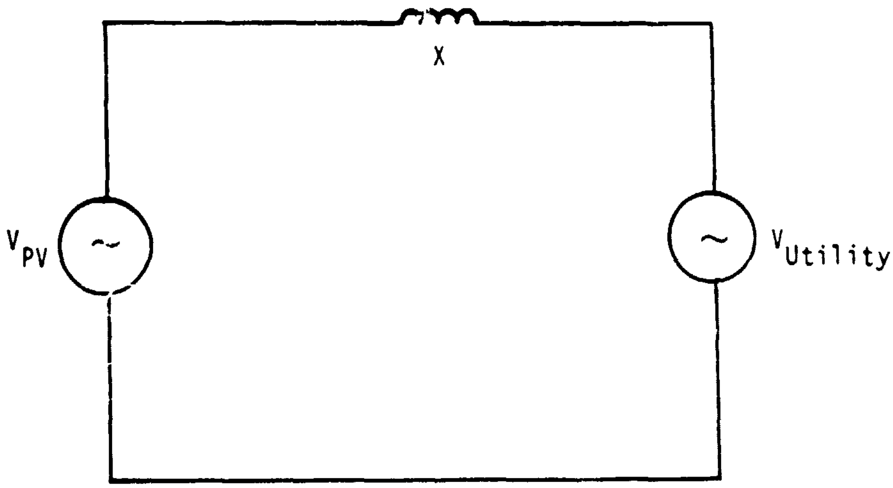

Figure 2-6. Simplified Schematic of a PCS Feeding a Utility

The current that flows is given by the expression:

$$i(t) = \frac{V_{PV}(t) - V_{Utility}(t)}{X}$$

Thus any substantial changes in V_{PV} or $V_{Utility}$ will cause excessive currents. In the case of rotating machines the inertia of the machine will help in stabilizing the rate of change of voltage magnitude, phase, and frequency.

b. <u>Discussion.</u> Contrary to rotating machinery, the PCS does not posess any inertia that could keep the inverter in synchronism with the utility that is in a transient condition. The conventional means of system protection therefore may not be sufficient to avoid PCS damage. The role of the conventional synchronizing relay is to separate the PV generator from the utility. Opening of the interconnecting circuit breaker triggered by this really may, however, not be fast enough Additional electronic protection within the logic must therefore be provided. Very little is known thus far about the requirements related to this interface.

D. UTILITY SYSTEM PROTECTION (OVERCURRENT AND OTHERS)

1. Definition

Protection of the utility distribution system (with distributed PV sources connected) includes proper protection under various faulted conditions so that the reliability of service remains unaffected.

2. Risk

A large number of distributed PV sources connected to the utility distribution system may adversely impact the time/current coordination of the various protective devices within the utility's primary distribution system. This would increase the probability of outages to the customers connected to the system.

3. Discussion

The overcurrent protection system is installed to perform numerous functions in a distribution system. Some of the functions include isolating permanent faults, minimizing fault location and clearing times, preventing equipment damage, and minimizing the probability of distruptive failure and safety hazards to public and system operating personnel. A typical overcurrent protection system for a radial distribution system is given in Figure 2-7. This system shows a three-phase main feeder protected with a three-pole circuit-breaker or recloser at the distribution substation. The single-phase lateral circuits are connected to the three-phase main through either fuses or sectionalizers. Any switching arrangements for sectionalizing or emergency ties to adjacent feeders are not shown here but do exist in practice.

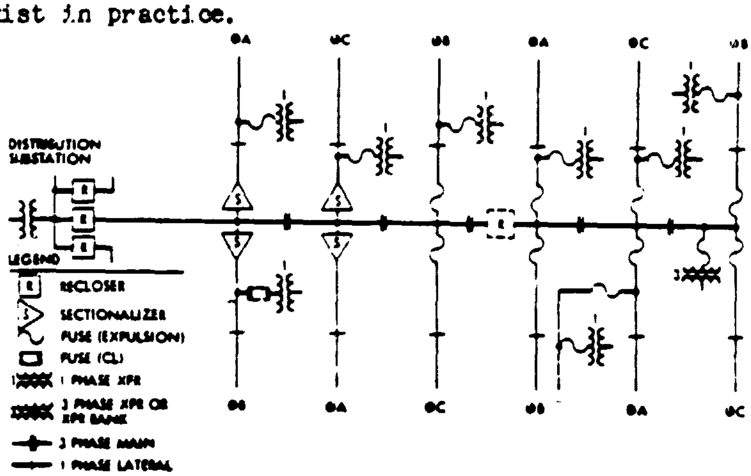

Figure 2-7. Simplified Single-Line Diagram of a Distribution Feeder to Illustrate Locations of Overcurrent Protective Devices (from Reference 6)

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To maintain a high reliability of electrical service, it is necessary that only faulted portions of the system be disconnected and isolated from the rest of the system. This is achieved by properly selecting protective devices (reclosers, fuses and sectionalizers) and coordinating them by their time-current characteristics. To properly use these characteristics, the lowest and highest expected values of the fault current observed by the protective devices must be known. In present day distribution systems, these values are determined by simple, short-circuit calculations because the only source of fault current is the utility system (ignoring small contributions to fault current by motors on the system). Even if the contribution of motors is included, simplified procedures have been developed to include their effect. Once the distributed PV sources are connected to the system, they will start contributing to the fault current, even though their overall current contribution will be much smaller than the utility system. Besides being a function of insolation (and thus the time of day), this portion of the fault current will be a function of the number of PV sources on the feeder and their location. The fault current contribution of the PV sources may not be great, however, it might be enough to adversely impact the time-current coordination of the protective devices on the system. Local tuned circuits might cause severe overcurrents which can also have adverse impacts on the coordination. To accurately determine fault currents with PV sources present, extensive fault studies must be carried out which would be much more complex than identical studies for present day systems.

E. REFERENCES

A number of references that were quoted and reviewed in the Report No. DOE/ET-20356-3* are equally relevant in the case of intermediate-size subsystems. They are listed below for a matter of record.

1. Photovoltaic Utility/Customer Interface Study, Final Report, Westinghouse Electric Corp., for Sandia Labs under Contract #13-2228, December 1980.

2. Kimbark, E. W., Direct Current Transmission, Vol. I, Wiley Interscience, 1971.

3. Assessment of Distributed Photovoltaic Electric Power Systems, Final Report by JBF Scientific for EPRI Project RP 1192-1, July 1980.

4. Study of Distribution System Surge and Harmonic Characteristics, Final Report EL-1627, prepared by McGraw-Edison Company for EPRI, November 1980.

*Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status, M. Hassan, J. Klein, September 1981, DOE/ET-20356-3.

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5. Application and Coordination of Reclosers, Sectionalizers and Fuses, IEEE Tutorial Course #80 EH 0157-8-PWR.

6. Surge Protection in Power Systems, IEEE Tutorial Course #79 EH0144-6-PWR.

7. Protection of Electric Distribution Systems Containing Decentralized Generating Devices, RFP PEDS-19, Oak Ridge National Lab for Department of Energy.

8. Impact of Dispersed Solar and Wind systems on Electric Distribution Planning and Operations, Final Report, SCI for Oak Ridge National Lab, Report #ORNL-SUB-7662-1, February 1981.

F. GUIDELINES/STANDARDS

The following is a list of articles which apply to intermediate PV installations and which were previously abstracted in DOE/ET-20356-3. Following this list, additional new references are abstracted.

1. Standard Voltage Values for Preferred Transient Insulation Levels, ANSI C92.1-1971.

2. Guide for Application of Valve Type Surge Arresters for AC Systems, ANSI C62.2-1978.

3. Surge Arresters for AC Power Circuits, ANSI C62.1-1975.

4. IEEE Guide for Protective Relaying of Utility-Consumer Interconnections, ANSI C37.95-1974.

5. Standards for Operating Reliability, California Public Utilities Commission Draft Report, Chapter 14.

6. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

7. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

8. Operating, Metering, and Protective Relaying Requirements for Parallel Operation by Small Cogenerators and Power Producers, 100 kW or Less, Pacific Gas & Electric Company, Draft Submitted to California PUC, September 1980.

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New References:

9. San Diego Gas & Electric Company. Protection and Operation Guidelines for Cogenerators and Small Power Producers, Preliminary Draft Submitted to California PUC.

   The excerpt from this draft pertaining to the protection of cogenerators less than 100 kW can be found in the Category I Document, (DOE/ET-20356-3). Listed below are requirements related to the intermediate-size systems between 100 kW and 1 MW:

   (1) The customer shall install relaying to provide adequate protection for the following:

      (a) All faults on the customer system involving phase and/or ground.

      (b) Faults on the SDG&E system involving phase.

      (c) Unbalanced or single-phase conditions on the utility system.

      (d) Prevent backfeed or start-up of the customer's generator(s) into a dead SDG&E bus.

   (2) The customer shall not reconnect his generator after a protective device trip unless his system is energized from the utility source, or unless he has isolated his system from the utility.

   (3) The above requirements are based on SDG&E's assumption that there will be a relatively small amount of customer generation vs. load for any particular line on the utility system. If a heavy saturation of small power production on some line(s) does occur in the future, the customer may be required to provide additional protection at that time.

10. Guidelines for Operating, Metering, Protective Relaying for Cogenerators and Small Power Procedures, Southern California Edison Company, June 1981.

   These guidelines summarize the minimum requirements for safe and effective operation of customer-owned generation on the Edison system.

   Edison insists that certain protective devices (relays, circuit breakers, etc.), specified by Edison, must be installed at any location where the customer desires to operate generation in parallel with the Edison system. The purpose of these devices is to promptly disconnect the customer's generating equipment from the Edison system whenever a fault or abnormal operation occurs. Two sets of requirements are outlined: one for power producers

generating 200 kVA or more, the other for system generating less than 200 kVA. The protection can be Edison or customer-owned, in the case of the total customer generation over 200 kVA. Single-line schematic of the first case indicates type and location of the protective elements required was shown in Figure 2-2.

G. CONCLUSIONS

There are no intermediate installation unique issues. Therefore, the conclusions of DOE/ET-20356-3 apply and are reproduced here for convenience.

(1) There is a substantial body of knowledge on the problem of surge protection for devices and distribution systems. The undesirable effects of voltage surges on converter equipment seem to be well known. It is thought that proper surge protection for PV systems can be provided based on the existing guidelines and standards for the surge protections of systems and appliances.

(2) Although the phenomenon of resonant overvoltages is well known and understood, it is very system-specific. Some preliminary guidelines are available for avoiding such resonances, but they are more "rule of thumb" than specific recommendations.

(3) Some preliminary studies indicate that the distributed PV system will have very little impact on the coordination of protective devices on the distribution system. However, the scope of these studies was very limited. More analysis is needed to substantiate this point of view.

(4) The protection of the PCS itself is an important issue. In the conceptual design of power conditioners for PV applications, specifications for protection such as under/over voltage, under/over frequency, loss of utility, etc., have been provided. However, it is felt that the selection of these protective devices should be based on a thorough system analysis of the operating environment in an actual utility interactive mode. The need to coordinate this protection with the utility is highly important.

(5) Some guidelines are now available from the utilities regarding protection requirements for dispersed generators. These guidelines should be reviewed for any installation of an intermediate PV installation.

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J. RECOMMENDATIONS

To solve the outstanding issues, a plan of action was recommended (see DOE/ET-20356-3, Figure 2-6, pg. 2-23). Some efforts have been made or are currently being made (by organizations such as DOE, EPRI, etc.) to address the various problem areas outlined within the Figure. The status of these efforts is summarized in Table 2-1. Column I describes the problem area. Column II gives the present status with a letter symbol. It also represents a worst-case future status if none of the proposed activities ever take place. Column III gives an optimistic projection of the future status. The future status is based on the premise that all the currently planned and proposed DOE (EES & PV) studies take place as scheduled. Column IV cites the references discussed in the body of the section which are responsible for any change in the status of the various problem areas.

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Table 2-1. Protection: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Assessment of Distribution Protection Practices	B	A	8
Development of Fault Analysis Models for Arrays and Power Conditioning Subsystem	C	C	-
Development of Software for Fault Analysis of Distribution System with Dispersed Generation	B	A	8
Determination of the Swing of Various Operating Variables During Faults with PV Connected	C	C	-
Determination of the Impact on Relay/Fuse Coordination	C	B	8
Selection of Proper Power Conditioning Subsystem Protection	C	C	-
Selection of Proper System Protection	C	B	8

A The issue is completely resolved or can be resolved when based on available knowledge.

B Much is known or documented, but the issue is not totally resolved.

C Very little is known or documented.

D Nothing is known or documented.

SECTION III

STABILITY

A. INTRODUCTION

Stability, in the conventional power system sense, refers to the ability of the system to maintain synchronous operation after a disturbance. In the control theory sense, it refers to the ability of the control system to direct the system to a new desired equilibrium state following a disturbance or any external stimulus. Note here that these are not rigid definitions, but are used to convey the sense in which stability is being used. For rigid definitions, please consult Reference 1 listed on page 3-4 or text books on control theory.

In the context of the present discussion, stability can be divided as shown in Figure 3-1. Each category is discussed below.

B. SOURCE STABILITY

1. Definition

Source stability is defined as the ability of an individual PV system, connected to the utility system, to maintain operation without large fluctuations in voltage, power, etc., such as might result from improper controls. The assumption here is that the PV generation power rating is far less than the size of the utility.

2. Risk

Any such fluctuations in output parameters could cause nuisance tripping of the PV source following a disturbance. In some cases, it could also cause damage to the PV system.

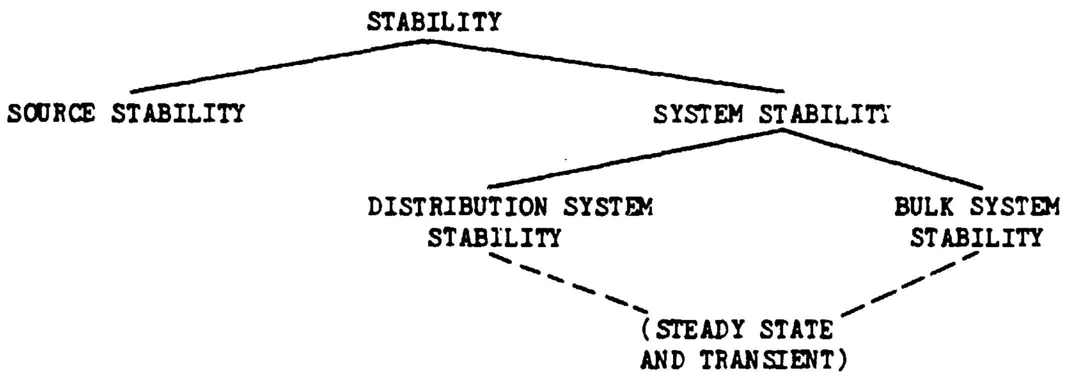

Figure 3-1. Stability Categories

3. Discussion

In all PV systems, it is highly desirable to extract all the available energy out of the array at each instant. This implies that the array must be operated at its maximum power point (or very near it) based on its voltage-current characteristics. This is achieved by a sophisticated control scheme that constantly tracks the critical operating parameters and adjusts the PV system operating point so that the maximum power transfer is obtained. Besides the maximum power tracker control loop, other control loops, such as the one for reactive power control, may be employed within the PV systems.

It is highly important that all these control loops operate in a stable mode under the wide fluctuations in operating parameters which can be expected in a utility interactive operation. These fluctuations could either be array specific, such as changes in available insolation, array temperatures, etc.; or utility specific, such as changes in voltage, frequency, etc.; or connection specific, such as resonances caused by or changes in the VAR compensation capacitance, etc.

The transfer functions of various elements of the control loops would determine the stability of the PV systems under the wide range of operating parameters described above. If the PV systems are found to be unstable or marginally stable under certain operating conditions, it may be necessary to modify the control systems to achieve stable operation.

At this stage, it should be clear that source stability refers to the interaction of a single PV generator with the rest of the utility system and not to the interaction between many PV power producers and/or the utility.

C. DISTRIBUTION SYSTEM STABILITY (BOTH TRANSIENT AND STEADY STATE)

1. Definition

Distribution system stability is the ability of many distributed PV generators and other DSGs (such as wind generators, fuel cells, batteries, etc.), connected to a single distribution substation, to maintain synchronous operation under the wide range of disturbances occurring on the system. (See Reference 1 for a detailed explanation of transient and steady-state stability.) The main assumption here is that any disturbance generated (such as tripping of a lateral or a primary feeder) as a result of any undesirable dynamic interactions between these various sources is confined to a feeder or a distribution substation and does not impact the bulk system.

2. Risk

Any undesirable interaction between various PV generators and DSGs connected to the same distribution system could cause nuisance tripping at the primary distribution or substation level causing unnecessary outages to the customers. It could also result in damage to customer equipment connected to the system.

3. Discussion

Technology is being developed for other DSGs including wind, fuel cells, batteries, cogeneration, low-head hydro, etc. These devices are eventually expected to be integrated into the utility system. In fact, some of these technologies such as low-head hydro, wind and cogeneration, are probably ahead of PV in terms of technology and commercial readiness. It is probably safe to assume that a future electrical distribution system will have a multitude of these sources connected to the system and, in many cases, to the same distribution feeder. This study was concerned only with specific problems with PV integration. However, it is highly important that all the PV generators operate reliably in conjunction with the other DSGs on the system.

As the operating characteristics of these different types of sources differ greatly, it is necessary to evaluate the dynamic interaction of the various sources with each other and with the utility system. It is quite possible that some of the undesirable interactions between these various sources will have a considerable impact on the design of the PCS.

D. BULK SYSTEM STABILITY (BOTH TRANSIENT AND STEADY STATE)

1. Definition

See Reference 1. The only disturbances of concern are the ones specifically attributable to the PV systems.

2. Risk

Any concern with bulk system stability could limit the maximum PV penetration on any given utility system.

3. Discussion

For stable system operation, the many synchronous generators connected to the system have to operate in mechanical synchronization. Any sudden disturbance on the system can cause one of the following end effects:

(1) The system will settle down to a new equilibrium state characterized by a new set of power flows within the network.

(2) The system will lose synchronization resulting in a chain reaction of line trippings and eventual system collapse.

The present power systems are so designed and operated that it would take a severe disturbance (loss of a big generating unit, fault on a loaded transmission line, etc.) to render the system unstable. System instability is something dreaded by the utilities. It can cause total system breakdown before any protective action can be taken. The historic blackout in New York City is an example.

With PV sources connected to the grid, system stability may not be a major concern until the PV penetration becomes quite high (5-10%). At that level of penetration, it would probably be more of a concern for large-scale central station plants than small-scale distributed systems. The obvious reason is that big plants can generate a larger disturbance on the system than small-scale units. An example of a disturbance is a rapidly passing cloud cover, which can drive the output power of the affected PV sources to a low value very rapidly. This is analogous to the loss of a generating unit in a utility with conventional generating sources. The resulting loss of power, if large enough in magnitude, could cause stability problems. However, this problem is system-specific and may have to be investigated on a one-to-one basis.

E. REFERENCES

The following references were abstracted in DOE/ET-20356-3. They are included here because they relate directly to intermediate systems.

1. <u>Proposed Terms and Definitions for Power System Stability</u>, IEEE Task Force on Terms and Definitions, Power Systems Engineering Committee, Paper #81 WM 082-7, IEEE-PES Winter Meeting, Atlanta, Georgia, February 1-6, 1981.

This paper is an effort to standardize electric utility industry terminology in the analysis of power system stability. Although most of the terms are not new, they have been defined precisely. In doing so, the historical use of the terminology was considered.

One interesting suggestion presented was to eliminate the term dynamic stability, which many referred to as the stability beyond the usual 1-second period covering the transient region. The new definition for transient stability is not time constrained.

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2. Merrill, W. C., et al, Performance and Stability Anaalysis of a Photovoltaic Power System, Report No. DOE/NASA/1022-78/30.

   This is a simulation study of the dynamics associated with a 10-kW PV system interconnected to a utility. A detailed model was developed of all components in the system including the inverter and solar arrays. The results indicated that, under good insolation conditions, stable operation was obtained. However, under low insolation conditions (20 mW/cm^2), limited cycle operation was encountered in the controls of the inverter. Thus, for interconnected operation, careful consideration to control parameters and feedback design must be shown to prevent undesirable operation.

3. Merrill, W. C., et al, An Inverter/Controller Subsystem Optimized for Photovoltaic Applications, Proceedings of the Thirteenth IEEE PV Specialists Conference, pp. 984-991, 1978.

   This study shows the development and analysis for a force-commutated inverter designed exclusively for a PV/utility application. The requirements were threefold:

   (1) A power system controller that can continuously control the solar array operating point at the maximum power level based on variable solar insolation and cell temperature.

   (2) An inverter that can operate at high efficiency at rated load and yet have low losses at light loading conditions.

   (3) An inverter that operates (at a level designated by the power (system controller) when connected to the utility.

   The simulation of the entire system showed good operating characteristics. Yet, at low insolation values, limit cycle operation appeared as in the previous study.

   It seems that care must be taken in the design of the controllers used to avoid this unwanted problem.

4. Beck, et al, A Computer Study of Battery Energy Storage and Power Conversion, IEEE Transactions on Power Apparatus and Systems, July/August 1976.

5. Fairchild, B. T., et al, Hybrid Simulation of Fuel Cell Power Conversion Systems, IEEE Transactions on Power Apparatus and Systems, pp. 1329-1336, July/August 1977.

   These two papers were combined because they deal with similar subjects in a similar manner. The studies use the hybrid computer to program the detailed models of the devices to be analyzed and

run transient studies. The papers analyze force-commutated and line-commutated inverters.

For force commutated inverters, there is dc current limitation due to the inherent characteristics of the inverter. Also, since there was no power factor control, reactive power compensation is required. Finally, under utility disturbances, large dc current transients were encountered.

For line-commutated inverters, there was a dc current runaway condition following ac faults. The study noted the need for a dc interruption device, and the need for reactive power compensation. However, outside of the fault condition, the line-commutated inverter was fairly insensitive to utility disturbances. Thus, the line-commutated inverter was recommended for large battery and energy storage installations.

6. Impact of Storm Fronts on Utilities with Wind Energy Conversion Systems (WECS) Arrays, Michigan State University, Report No. COO/4450-79/2.

This study is a good step in understanding the difficulties a utility has with a large penetration of intermittent sources. The study presents the results from two types of farms; (1) coastal: broad, shallow field, usually only a couple of rows deep, and (2) midwestern: a square farm. The coastal farm will have larger transients during storm fronts because more generators are affected at any given point in time. The midwestern farm has a more staircase nature from the fewer number of generators affected.

Under the conditions studied, the coastal farm caused the Automatic Generation Control (AGC) System to saturate, thus allowing a large disturbance in the frequency. In all, a 7.5% change in generation was required within 10 minutes to return the frequency to within limits.

For the midwestern farm, the staircase nature of the WECS output caused cycling of the nuclear plants. This is a highly undesirable mode. Because the nuclear units are designed as base load units and not cycling units, their efficiency falls off as a cycling plant.

7. Ewart, Donald N., and Schultz, Richard P., Use of Digital Computer Simulation to Assess Long-Term Power System Dynamic Response, IEEE Transaction on Power Apparatus and Systems, Vol. PAS-94, No. 3, May/June 1975.

This paper describes the use of typical long-term dynamic codes to show the effects of controls. It also shows the benefits of event simulation: what occurred, when, and why. Such tools are needed

to study the dynamic interaction between PV systems and the rest of the utility.

8. Photovoltaic Transient Analysis Program, BDM Corporation, Report No. SAND 78-7083, Sandia National Lab.

   This program allows the user to specify the type of array and peripheral equipment to be studied. It has detailed models for the PV array, allowing for parallel and series connections; for the solar cells, using the Ebers-Moll model; and for heat transfer characteristics. Unfortunately, very little detail is provided on the inverter, its controls, or the other auxiliary equipment on site.

   Once the models have been constructed, the user can perform steady-state, transient, and small excursion ac analysis.

9. Dynamic Simulation of Dispersed, Grid-Connected Photovoltaic Power Systems, Statement of Work 62-4092, Sandia National Lab, December 1980.

   The basic objective of this task is to study the dynamic interaction of distributed PV systems with the electric utility grid. The primary emphasis of the study is the behavior of PV systems at the utility interface. The study did not model system disturbances such as lightning and switching surges, nor did it model electrical dynamics for longer than several seconds.

   There are four basic tasks ennumerated in the Statement of Work:

   (1) Task I: PV System Model Development. This task will develop the appropriate dynamic electrical models for a set of representative PV systems. The typical sizes of power conditioning equipment to be modeled are 5 kW, 240 V single-phase, 10 kW, 240 V single-phase, and up to 250 kW, 480 V three-phase. These could include self-commutated and line-commutated as well as advanced control techniques such as high frequency conversion and ferroresonant transformer control. An indepth study of the control system for each of the inverters under consideration be made. If deficient controls are found, new controls will be designed.

   (2) Task II: Distribution System Simulation. After the PV system models have been developed for Task I, each PV system will be simulated on representative distribution systems. Not only will each PV system be modeled on several distribution circuits, but several types of PV systems will be modeled simultaneously on the circuits. The dynamic simulation would include both low and high PV system penetrations in the distribution circuit, such as 0-10% at the feeder, 0-25% at the primary distribution substation, and 0-100% at the secondary distribution system.

(3) Task III: Transmission System Simulation. Task III will involve extrapolation from the individual models described in Task I and the distribution network simulation performed in Task II. This will represent the collective effect of significant penetrations of PV systems on the dynamic stability of the utility generation and transmission systems.

(4) Task IV: Interpretation of Simulation. This task will summarize the findings from the other tasks and provide a physical description of the nature of anticipated problems. It is also intended to provide recommendations for circuit modification and control system changes to overcome any problems. Also, it would identify the percentage of PV penetration where problems begin to appear for various inverter models in the dynamic interaction with the electrical utility grid.

There is a major question as to whether the proposed study can achieve all its objectives within the resources allotted. However, it is an important step to better understand the dynamic interaction between the PV system and the utility grid.

10. Interaction Between an OTEC Power Plant and a Power Grid, Ongoing DOE/EES Contract with ERDI (Energy Research and Development International).

This study investigates the interaction of an OTEC power plant with the Puerto Rico Electric Power Authority electrical power system. The project would develop suitable OTEC models for both steady-state and dynamic analysis and use standard computer codes to perform the analysis.

F. STANDARDS/GUIDELINES

None exist on this particular issue.

G. CONCLUSIONS

No new issues were identified for intermediate systems. The type of models and issues discussed below now relate to three-phase models rather than one-phase models.

(1) Although the problem of bulk system stability is well understood, very little is known about the stability problems of dispersed PV systems. Some initial studies with individual PV systems show that stability problems might develop.

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(2) Little is known about the dynamic interaction of many PV systems with each other and with the utility system. Because future distribution systems might also contain other DSGs, the dynamic interaction of dispersed PV systems and DSGs also must be determined.

(3) Little knowledge is available on the aggregation of PV sources and PV sources with other DSGs. As the penetration increases, the technique must be developed so that affects on source, bulk system, and distribution stability can be found.

H. RECOMMENDATIONS

Table 3-1 gives the status of those areas which require further efforts. The successful completion of each of those efforts should eliminate most of the problems associated with stability.

Table 3-1. Stability: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Dynamic Models of PV Systems	C	A	9
Dynamic Models of DSGs	C	B	6,9,10[a]
Dynamic Aggregation Model of DSGs	C	C	9
Dynamic Analysis Techniques	C	A	9
Impact on PV Control System	D	B	9

[a] DOE also has many ongoing research activities in the area of wind system modeling.

A The issue is completely resolved or can be resolved when based on available knowledge.

B Much is known or documented, but the issue is not totally resolved.

C Very little is known or documented.

D Nothing is known or documented.

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SECTION IV

VOLTAGE REGULATION AND REACTIVE COMPENSATION

A. INTRODUCTION

1. Definition

The term voltage regulation refers to proper maintenance of the voltage at the customer's terminals, within an acceptable range with PV generators connected [2], while also maintaining the flow of reactive power within limits.

2. Risk

If the utilities are responsible for maintaining proper voltage at the customer's terminals, inclusion of a PV generation may necessitate changes of the control system. The costs of such changes may have to be passed on to the owners of the PV generators.

3. Discussion

When PV generators are connected to the utility distribution system, the problem of proper voltage regulation is complicated due to the following reasons:

(1) In the present day distribution systems the flow of power is in one direction only. It is quite simple to analyze the one-way power flow on a radial distribution system and determine the voltage levels and I^2R losses within the system. With distributed PV sources on the system, such an analysis can become quite complicated because of the possibility of bidirectional power flow. In addition, better models will have to be developed for the PV generators, voltage regulations and loads.

(2) Line-commutated inverters operate at lagging power factors. In other words, they draw reactive volt amperes (VARs) from the system. The utility system must be in a position to supply the additional VARs needed to satisfy the load requirements. Because most of the real power demand of the loads is expected to be met by the PV systems, the utility system is left with supplying relatively large amounts of reactive power, but very little real power during high isolation levels. Thus, the ratio of VARs to real power (watts), as seen by the voltage regulator at the distribution substation, could be fairly high. This, in turn, could have an adverse effect on the voltage regulation of the system besides

causing some secondary concerns such as higher I^2R losses, overloading of system components, etc. This problem could be alleviated by using power-factor correction capacitors. Unless switched capacitors are employed, which can be switched off during low insolation conditions, overvoltages might be experienced on the system. It should also be recognized that a self-commutated inverter can be operated at a unity power factor or possibly even a leading power factor. At this stage, however, it is not clear that a unity power factor inverter is the answer because the ratio of VARs to watts at the substation would still be rather high.

(3) For power systems operating under sinusoidal conditions, there is a relatively simple correspondence between the reactive power flow and voltage regulation, and voltage regulation is achieved through reactive power control. In addition, power factor and reactive power are clearly interlinked quantities. Because the inverters deliver not purely sinusoisal waveforms, all these quantities cannot be analyzed, visualized or interpreted as in the conventional utility sense. There is a need, therefore, to develop methods of analyzing issues of power factor control, voltage regulation and reactive power control under non-sinusoidal conditions. The IEEE Std. 519-1981 (see pg. 4-5) and various other authors (as mentioned in DOE/ET-20356-3) have defined power factor under non-sinusoidal conditions differently and their implications have to be studied.

B. REFERENCES

The following references were abstracted in DOE/ET-20356-3. They are included here (and shortened) because of their direct applicability to intermediate systems.

1. <u>Study of Dispersed Small Wind Systems Interconnected with a Utility Distribution System</u>, Interim Report by Systems Control Inc. for Department of Energy Contract #DE-AC-04-76DP03533.

   The study conclusion on voltage regulation is that utilities will not have serious voltage regulation problems because:

   o The addition of small wind systems to a feeder will not occur suddenly; rather, wind-turbine generators will be added in small increments throughout the utility's system. If, by chance, many are added to a particular feeder, the voltage profile will change gradually.

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- Utilities adjust voltage regulation equipment for normal load growth. Wind-turbine generators added to a feeder will influence this normal adjustment procedure only slightly.

Based purely on the conclusions of this study, if dispersed wind systems do not pose a problem for voltage regulation (up to 50%) penetration on a feeder, it is hard to imagine that PV systems would behave any differently.

2. Assessment of Distributed Photovoltaic Electric Power Systems, Final Report by JBF Scientific for EPRI Project RP 1192-1, July 1980.

The initial findings of this study indicate that large backflows from distributed PV installations would interfere with the operation of voltage regulators and LTC controls under light loading conditions. One possible remedy could be to limit PV penetration to less than 30% for the different cases examined. It was also found that reactive power requirements from some distributed PV systems (using line-commutated inverters) tend to increase voltage drop. The recommendation is to require PV installations to have power factors in excess of 0.9.

The thrust of the study is more an economic analysis than a technical analysis. However, it does provide some interesting insight into the problems that could be expected with distributed PV systems.

3. Fernandes, Happ, and Wirgau, Optimal Reactive Power Flow for Improved Systems Operations, Electrical Power and Energy System, Vol. 2, No. 3, July 1980.

The utilization and coordination of reactive sources and other voltage control equipment in system operations are discussed. The reactive sources studied are generators, synchronous condensers, switched static capacitors and shunt reactors, as well as transformers with and without load-tap changing capabilities. The benefits derived from the method presented include savings in fuel production costs, unloading of system equipment, improved system security, and improved voltages over the system.

4. Shepperd, W., et al, Power Factor Correction in Non-Sinusoidal Systems by the Use of a Capacitance, Applied Physics, Vol. 6, p. 1850, 1973.

The apparent voltamperes of an non-sinusoidal circuit can be considered as the result of three hypothetical components known as the active voltamperes S_R, the true reactive voltamperes S_x, and the apparent distortion voltamperes S. In systems with non-sinusoidal voltages, the active voltamperes S_R differs from the average power P, and the true reactive voltamperes S_x differs from the quantity,

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$Q = \sum_{1}^{n} E_n I_n \sin_n$, frequently quoted in the literature.

The reactive voltamperes of an inductive load can only be completely compensated by capacitance to give a unity power factor, when the load impedance is linear and the voltage is sinusoidal. If the load impedance is nonlinear, the load voltage is non-sinusoidal or both. Some improvement of power factor may be realizable by capacitance, but the highest power factor achievable is less than unity.

Equations are developed to give the maximum power factor and the minimum reactive voltampers achievable by capacitance compensation. The optimum value of capacitance to give maximum power factor operation is defined for the cases of non-sinusoidal voltage supplying a nonlinear load, non-sinusoidal voltage supplying a linear load, and sinusoidal voltage supplying a nonlinear load.

5. Impact of Dispersed Solar and Wind Systems on Electric Distribution Planning and Operations, Final Report, SCI for Oak Ridge National Lab, Report #ORNL-SUB-7662-1, February 1981.

This study examined the effects of dispersed solar photovoltaics and wind systems on distribution system operation. The findings regarding impacts on voltage regulation are summarized below.

When dispersed sources produce power, their output changes the feeder's voltage profile. Voltage source generators (such as self-commutated inverter systems and synchronous generators) produce their own reactive power and tend to increase the voltage at the point of connection by reducing the load. Current sources such as line-commutated inverter systems and induction generators draw reactive power to produce real power output. They also tend to increase the voltage, but to a lesser extent than voltage-source generators.

In general, as the penetration of dispersed sources increases along a feeder, the minimum and maximum voltage points on the feeder increase. This happens irrespective of the generator type, i.e., voltage sources or voltage-dependent current sources. For low penetration, 5 and 20%, the increased voltage profile does not exceed the utility's maximum voltage criteria. However, higher penetrations cause the maximum voltage criteria to be exceeded.

In all cases examined, the dispersed generators narrowed the range between the feeder's minimum and maximum voltage points. This is caused by the high resistance characteristics of the distribution feeder. As load is reduced by the output of the dispersed generators, the real current is reduced, significantly increasing the voltage. The effect is seen clearly when comparing the synchronous generator and the induction generator cases. Although

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the induction generator increases the reactive current, there is very little difference between the two voltage profiles.

The assertion made in the study that distribution feeders exhibit high resistance characteristics is not totally correct. This may be true for underground feeders, but is certainly not valid for overhead distribution feeders, where line reactance predominates over line resistance.

C. GUIDELINES/STANDARDS

1. IEEE Guide for Harmonic Control and Reactive Compensation for Static Power Converters, IEEE Std. 519-1981.

   This guide applies to all types of static power converters used in industrial and commercial power systems. It discusses the problems, serves as an application guide and recommends limits of disturbances to the ac power distribution system which affect other equipments and communications.

2. Voltage Ratings for Electric Power System and Equipment (60 Hz), ANSI C84.1-1970, including Supplement C84.1a-1973.

   This guideline gives standard voltage ratings used in electric power system and equipment applications.

3. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

   The guidelines regarding reactive power generation and voltage regulation are:

   o The operation of the production facility shall not produce excessive reactive power during offpeak conditions nor consume excessive reactive power during onpeak conditions.

   o The owner shall provide necessary voltage regulation equipment to prevent the production facility from causing excessive voltage variation on the connecting electric system. The voltage variation caused by the production facility must be within ranges capable of being handled by the voltage regulation facilities used by the connecting electric system.

   The ranges of reactive power consumption/generation and the voltage variations are not specified at all.

4. Interconnection Facility and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

The characteristics of individual utilities are too varied to recommend a particular alternative that would be appropriate for all utilities. Therefore, each utility should develop its own power factor standard(s) applicable to qualifying facilities (QFs). In the process of doing so, each utility should evaluate its (1) system needs, (2) rates and other provisions developed for application to the QFs, and (3) assumptions on the number and type of QFs expected.

Regarding voltage regulation, it is recommended that each QF applying for service be required to provide a reasonable estimate of its load without generation, and the capacity, type, and operating characteristics of the QF.

Should the maximum utility voltage limits be violated, then the QF should be disconnected, or not allowed to be connected, until the unacceptable voltage is corrected.

Utility rules and regulations should be changed or expanded, as necessary, to require voltage regulation by QFs within limits acceptable to the utility.

5. San Diego Gas & Electric Company, Protection and Operation Guidelines for Cogenerators and Small Power Producers, Preliminary Draft submitted to California PUC.

The excerpts from this draft pertaining to voltage regulation are:

- The customer should maintain his power factor within a reasonable range. For small generators, power factor correction is not required.

- Voltage regulation equipment will be required on the customer's generator to maintain service voltage within normal utility limits. If high or low voltage complaints or flicker complaints result from operation of the customer's generation, such generating equipment shall be disconnected until the problem is resolved.

D. CONCLUSIONS

(1) Initial study of dispersed generation has shown that the impact on voltage regulation is quite minimal unless the penetration gets quite high (around 50%). However, reverse power flows and changes in power factor can cause improper operation of voltage regulators.

(2) For converters operating at lagging power factors, it may be more economical to correct the power factor using capacitors than having the utility supply VARs and charge for it.

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However, using capacitors on the system can cause undesirable interaction with harmonics (system resonances).

(3) Utility guidelines studied did not specify any band within which the dispersed generator (PV system, for example) had to regulate its voltage.

(4) Mathematical model of PV system including effects of PCS and load flow analysis using this model are key to the issues of voltage regulations and reactive power compensation.

E. RECOMMENDATIONS

Various definitions of power factor and reactive power in power systems with three-phase PV generator and non sinusoidal operating conditions must be field tested. In addition, load flow analyses will have to be performed, including the effects due to PV systems. Better models have to be developed for the PV systems, voltage regulators and loads.

Table 4-1 shows the present status of these issues.

Table 4-1. Voltage Regulation: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Assess Present Distribution Practices	B	A	Section IX (2)
Develop Steady-State Models of Converters	B	B	-
Study System Resonances	C	C	-
Assess System Modifications to Maintain Required Voltage and Power-Flows	C	C	-

A The issue is completely resolved or can be resolved when based on available knowledge.

B Much is known or documented, but the issue is not totally resolved.

C Very little is known or documented.

D Nothing is known or documented.

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SECTION V

HARMONICS

A. INTRODUCTION

1. Definition

The term harmonics, as used here, refers to the amount of voltage and/or current harmonics (other than the fundamental component) produced by a PV system (at its terminals) when connected to a utility power system. The smaller the total harmonic content of the PV system output, the better it is for the utility and the customer. The maximum allowable harmonic content may be fixed by the utility.

2. Risk

Harmonics (both current and voltage) have a lot of undesirable effects associated with them. If a PV system produces excessive harmonics and thereby causes problems with the utility power system, the utility may ask the PV system to correct the situation or to disconnect. It should be noted that the output filters of power conversion systems may be damaged due to injection of high frequency circulating current harmonics present on the line.

3. Discussion

Even without the presence of PV sources, there are already many other sources of harmonics on existing distribution systems. In general, devices with nonlinear operating characteristics produce harmonics. Some examples are transformer magnetizing currents, arc furnaces, welders, thyristor controlled devices, rectifiers, pulsating prime-mover torques, etc.

The introduction of PV sources into the grid will magnify the level of harmonics on the system due to the harmonics produced in the dc to ac conversion process. Of the various types of power conversion alternatives available, two approaches commonly applied today and discussed in Section I produce different types of harmonics. The Current Fed Line-Commutated Inverter (CFLC) produces current harmonics while the Voltage Fed Force-Commutated Inverter (VFFC) produces voltage harmonics. In both cases, the level of harmonics imposed on the system is a function of system impedance at the point of interconnection as well as the characteristics of the inverter itself.

The order of harmonics produced by either type of converter is a function of the switching design and can generally be classified into the following categories:

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(1) Characteristic harmonics: These harmonics are produced by semiconductor converter equipment in the course of normal operation.

(2) Uncharacteristic harmonics: These harmonics are those that are not produced by semiconductor converter equipment in the course of normal operations. These may be results of beat frequencies, a demodulation of characteristic harmonics and the fundamental, or unbalance in the ac power system or unsymmetrical delay angles.

(3) High frequency harmonics: These harmonics in the tens of kHz range are produced due to commutation notches in the supply voltage.

The undesirable effects of harmonics are summarized below. No effort is made to isolate effects from voltage or current harmonics because they are essentially duals of each other, i.e., one produces the other.

(1) Overheating of capacitor banks due to low impedance to higher order harmonics.

(2) Overheating in rotating machines and transformers. Harmonics do influence motor torque also, but this effect is not thought to be significant.

(3) Interference with utility ripple and carrier current systems.

(4) Interference with voice communication (telephone interference).

(5) Overvoltage due to resonance.

(6) Instability in converter controls.

(7) Malfunctioning of protective relays.

(8) Errors in metering real and reactive energy.

(9) Malfunctioning of connected loads, such as computers.

Development of a viable standard for harmonic limits of individual power conditioning units could be a very complex procedure. It would involve determining the maximum allowable harmonic limits at any point on the system and translation of this number into an allowable harmonic injection (voltage or current) at the terminals of the converter. This limit would depend on the characteristics of the distribution system, on background harmonic level from other sources on the system, and most importantly, on the penetration level (both

local and system-wide) of PV sources. It would also involve extensive system simulation and field measurements.

At present no standards exist for the harmonic output of power inverters. If a customer using such a device for parallel generation is found to be interfering with other customers or utilities, or if standards are adopted in the future, the generating customer may be required to install filtering to bring the harmonic output of his inverter to an acceptable level (Reference 10 in Section II.F).

IEEE has prepared a Guide (Reference 5 in Section C) for Harmonic Control and Reactive Compensation of Static Power Converters for Systems above 460 V. Section 8 of this guide deals with recommended practices and deals with line notch limits, voltage distortion limits, telephone influence factor limits and flicker limits for low, medium and high voltage power sources.

B. REFERENCES

A number of references quoted and reviewed DOE/ET-20356-3* deal with the residential PV subsystems but are equally relevant in the case of intermediate size subsystems. These references are again listed below for a matter of convenience. They are supplemented by a set of new references.

1. Kimbark, E. W., Direct Current Transmission, Vol. I, Wiley Interscience, 1971.

   This book offers an excellent treatment of harmonics. Chapter 8 contains useful information related to the generation of voltage and current harmonics by HVDC converters.

2. Study of Distribution Systems Surge and Harmonic Characteristics, Final Report EL-1627, prepared by the McGraw-Edison Company for EPRI, November 1980.

   This study identified various sources of harmonics on distribution systems and their effect on the various equipment. It also demonstrated that satisfactory instrumentation for measuring harmonic currents and voltages is available. The field tests demonstrated the validity of using analytical models of ac/dc power converters to predict the magnitudes of harmonics generated on the system. Computer analyses predicted frequencies causing resonance or current/voltage magnification to an accuracy of within 5%. Magnitude predictions varied with the location. Near the harmonic source, the results were no less than 50% inaccurate

*Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status, M. Hassan, J. Klein, September 1981, DOE/ET-20356-3.

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(on the order of 20% inaccurate for harmonics below 19th). Far from the harmonic source, inaccuracies of several hundred percent were encountered.

New References

3. Electrical Noise and Harmonics on Power Systems Measurements, ongoing project, EPRI RP 2017.

   This is a new start by EPRI directed at field measurements of noise and harmonics on a total of 100 feeders in distribution systems of 10 utilities. Anticipated completion is March 1983. The results should provide valuable data on present levels of harmonics and noise (without DSGs).

4. Ainsworth, J. D., Harmonic Instability Between Controlled Static Converters and AC Networks, IEEE, Vol. 114, July 1967.

   A controlled mercury-arc or thyristor converter with a conventional firing-pulse control system can both generate and magnify ac harmonics additional to the fifth, seventh, etc., of classical converter theory. This effect is normally of little importance if the impedance of the ac system is low, but it is shown by analysis that, if this impedance is relatively high, as may occur on the larger sizes of converter in HVDC transmission, this type of harmonic magnification may become excessive and may even prevent stable operation of the converters. The analysis is confirmed by model tests and appears to account for several reported instances of excessive abnormal harmonics associated with firing-angle unbalance in HVDC converter installations. Generation of abnormal harmonics can be substantially reduced and harmonic magnification largely eliminated by a new control system in which firing pulses are timed by a phase-locked oscillator, controlled to satisfy the usual constant-current or extinction-angle requirements.

5. Measurement of Harmonics, ongoing DOE/EES contract with the National Bureau of Standards (NBS), Contract #AC01-80RA-50215.

   This is a continuing project with funding first received from the DOE in April 1980. Preliminary design work at NBS started earlier in FY 1980. The program consists of two main tasks: (1) developing methods and associated instrumentation to accurately measure electrical power highly distorted waveforms (specifically, a sampling type wattmeter with ±0.1% accuracy, traceable to the basic NBS standards, will be developed and one prototype built), and (2) developing methods and the necessary physical standards to accurately characterize and calibrate wideband, high-current shunts utilized in electric power train systems. An NBS-designed impedance bridge will be modified to provide an accuracy of ±2% or better in the value of these transducers of over the frequency range from dc to 100 kHz.

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In FY 1980, an improved simulation program for wideband sampling was developed, with an analysis of the major sources of error due to two-channel sampling, digitizing, and signal processing. Assembly and initial check-out was completed for the 16-bit microcomputer and associated peripheral devices display, direct-memory acess (DMA) multiplier-accumulator, etc., comprising the digital signal processing hardware of the prototype wattmeter. Current shunts submitted by NASA Lewis Research Center (LeRC) were tested over the frequency range from 400 Hz to 10 kHz. The performance was different than expected from a well-designed coaxial resistor.

C. GUIDELINES/STANDARDS

1. IEEE Guide for Harmonic Control and Reactive Compensation for Static Power Converters, IEEE Std 519-1981.

This guide applies to all types of static power converters used in industrial and commercial power systems. It discusses the problems, serves as an application guide and recommends limits of disturbances to the ac power distribution system which affect other equipments and communications. This guide is not intended to cover the effect of radio-frequency interference.

IEEE has established three classes of low-voltage systems to determine the limits of distortion that may be allowed from static power converters. The criteria for measurement in these systems include:

DF = Voltage distortion factor (DF = $V_L(\sum_{1}^{n} V_n^2)^{1/2}$), it is the

sum of the root-mean-square of the harmonic content to the RMS value of the fundamental component.

Table 5-1 shows low voltage system classification and distortion limits for systems between 460-V and 2400-V levels.

Table 5-1.

Distortion Limits for Low Voltage Systems

Class	ρ	AN	DF%
Special Applications*	10	16,400	3
General Applications	5	22,800	5
Dedicated Application	2	36,500	10

*Special applications are those where the rate of change of voltage of the notch might mistrigger an event.

Where: $$\rho = \frac{Xs + Xt}{Xs}$$

ρ: Impedance ratio of total impedance to impedance at common point in system.

Xs: System reactance.

Xt: Converter reactance.

AN: Area of commutation notch in volt-microseconds.

DF: Distortion factor in %.

Table 5-2 presents the voltage distortion limits for medium (2.4 kV to 69 kV) and high (above 115 kV) voltage power systems.

Table 5-2. Voltage Distortion Limits for Power Systems

Power System Voltage Level	Dedicated* System Converter	General Power System
Medium Voltage (2.4 - 69 kV)	8%	5%
High Voltage (115 kV and above)	1.5%	1.5%

*A dedicated system is one servicing only converters or loads not affected by voltage distortion.

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2. "Guidelines for Allowable Harmonic Voltages for HVDC Applications" (from Reference 1 above).

These guidelines are parts of Reference 1.

Limits of harmonic voltage/current for various HVDC projects as proposed by Kimbark are tabulated in Table 5-3.

Table 5-3. Limits on Harmonic Voltage/Current for HVDC Systems

Project	Limits on Maximum Deviation from Sine Wave* (H_6),%	Limits of Every Characteristic Harmonic Voltage, %
Ainsworth	3-5	—
King North	2.5 (for characteristic harmonics only)	1
Sardinia	4	—
New Zealand	—	0.7

H_6 is defined as = $\frac{\sum_{h=2} I_h}{I_1}$

where: I_h = harmonic current of order h, I_1 = fundamental current.

D. CONCLUSIONS

(1) There also exists a guideline for harmonics produced an installation interconnected at 460 V and above.

(2) The progress of these guidelines to standards should be followed closely.

(3) Further effort is required to develop better methods for harmonic reduction. Various combinations of VFFC logic methods and for switched VAR compensators may solve the problem. Detailed analysis is still required to predict the high order harmonic resonances that have been seen in various situations.

(4) Studies must be performed that document the interaction between harmonic sources. Do they enhance or cancel the harmonic?

(5) The characteristics of various classes of loads in the harmonic range (up to 23^{rd} as a minimum) must be found so that the effects of harmonics on loads can be predicted.

(6) Detailed cost studies must be performed to understand the tradeoff between harmonic suppression method (filters, etc.) and resulting customer effects in terms of performance, inconvenience and cost.

E. RECOMMENDATIONS

Table 5-4 gives the status of those areas which require further efforts. The successful completion of each of these efforts should eliminate most of the problems associated with the presence of harmonics.

Table 5-4. Harmonics: Status of Problem Areas

Problem Areas	Present Status	Future Status	Reference Numbers
Tolerable Harmonic Levels	C	B	8
Measurements of Background Harmonic Levels on Systems	C	A	2,13
Load Characteristics	C	B	
System Software to Study Interaction	C	B	14
Specify Limits for Individual Sources	C	C	-

A The issue is completely resolved or can be resolved when based on available knowledge.

B Much is known or documented, but the issue is not totally resolved.

C Very little is known or documented.

D Nothing is known or documented.

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SECTION VI

SAFETY AND CODE REQUIREMENTS

A. INTRODUCTION

1. Definition

The discussion that follows includes development of safety requirements for PV systems connected to the utility power system. The object is to minimize the potential of a shock hazard to either the owner of a PV system, or to the utility operating personnel, and to also prevent the possibility of destruction of property from a fire.

2. Risk

Unless appropriate requirements are established within the existing framework of product safety standards, building and electrical codes, and utility codes, it will be very difficult to obtain the necessary approval from either the utility or local code enforcement officials.

3. Discussion

It is highly important that PV systems connected to a utility system should not cause any safety hazard to either the PV source owners or to utility personnel. The safe installation of commercial and industrial electrical systems is guided by the National Electric Code (NEC), which is published by the National Fire Protection Association (NFPA) every 3 years. The code, as written now, does not address photovoltaics. It is anticipated that revisions to the NEC will emphasize the unique aspects of photovoltaics and address those concerns which could result in an unsafe installation. Some issues of concern are grounding of PV arrays and the PCS, disconnection of the PV array from the PCS and the PCS from the utility in case of an emergency or during times of maintenance. These and other issues directly impacting safety must be thoroughly analyzed and included in the next revision of the code.

B. REFERENCES

A number of references quoted and reviewed in DOE/ET-20356-3* deal with the residential PV subsystems but are equally relevant in the case of intermediate size subsystems. They are again listed below for matter of record.

1. Photovoltaic Utility/Customer Interface Study, Final Report, Westinghouse Electric Corp. for Sandia, under Contract #13-2228, December 1980.

   Chapter 2 discusses the possible methods of interconnecting PV systems with the utility and their acceptance under the NEC. The report also tabulates the list of typical protection devices required for the interface, assuming, however, that the PCS is provided with its own protection. The requirements of grounding PV systems are briefly discussed based on articles of the NEC describing various grounding practices.

   Although some interesting comments are made about the applicability of PV systems to NEC, the treatment is very brief.

2. Investigation Protection of Electric Distribution System Containing Decentralized Generating Devices, RFP PEDS-19, Oak Ridge National Laboratories for the Department of Energy.

   The final study task involves an analysis of personnel safety. Current practices will be reviewed and modifications suggested. Hardware requirements to meet safety modifications will be discussed.

3. DOE/PV Sponsored Studies with Underwriters Laboratory (UL).

   Currently, there are two DOE/PV-sponsored studies going on at Underwriters Laboratory to investigate the grounding and safety requirements for the PV array and the PV Interface Subsystem. The studies are managed by JPL and SERI respectively. Hopefully, at the completion of the studies, viable safety requirements will be developed to ensure adequate safety to the PV owner and to utility personnel.

C. GUIDELINES/STANDARDS

1. National Electric Code (NEC), published by the National Fire Protection Association (NFPA) as NFPA70/ANSI C1.

   This guideline is followed extensively by local code enforcement officials for approval of electrical installations.

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*Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status, M. Hassan, J. Klein, September 1981, DOE/ET-20356-3.

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2. National Electric Safety Code (NESC), ANSI C2-1981.

This standard is published by the IEEE. It is applicable to the systems and equipment operated by utilities, or similar systems and equipment on an industrial establishment under the control of operational personnel.

3. Standards for Operating Reliability, California Public Utilities Commission Draft Report, Chapter 14.

For various issues regarding safety, the PUC gives the following recommendations:

(1) Except for the utility manual disconnect and feeder reclose blocking equipment, the QF shall have the option of owning (furnishing and installing), operating, and maintaining the interconnection protective equipment or paying for the utility to install the equipment and maintain it.

(2) The utilties shall review their requirements for small size facilities to simplify requirements and standardize. Dedicated transformer requirements that the QF may be required to pay for shall be limited to no greater than 1.15 times the QFs generator nameplate capacity.

4. Tennessee Valley Authority Proposed Policy on Dispersed Power Production and Interim Program and Guidelines for Implementation, Federal Register, Vol. 45, No. 234, December 3, 1980.

The safety and groundi guidelines are:

(1) In order to provide safety for the connecting electric system employees performing emergency repairs or routine maintenance to its lines, the owner must provide equipment for disconnecting and isolating the production facility during electric system interruptions. Such equipment must be capable of preventing the production facility from energizing the systems lines during such interruptions. It must include a device (or devices) which the electric systems employees can operate and lock to isolate the production facility and all means of backfeed into the connecting electric system.

(2) The facilities (generator, connecting transformer, etc.) that connect to the electric system must be grounded so that coordination is maintained with the relay protection system used by the connecting electric system and so that the connecting facility is not subjected to deleterious voltages during fault conditions.

ORIGINAL PAGE IS
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5. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

The specific guidelines provided for safety, isolation, and grounding are as follows:

(1) A utility controlled device (switch) which physically and visually opens the circuit to the QF, must be provided. The device:

(a) Must open all cables to the device including the neutral.

(b) Must be operable by utility personnel at any time without notice to the QF and without restricted access.

(c) Must be lockable in the open position by the utility.

The disconnecting switch should simultaneously interrupt all phases, and neutral cables between the utility and QF generation. Under energized conditions, this will preserve the electrical continuity of cables interconnecting the utility and QF and prevent voltage problems and safety hazards that could occur if electrical continuity was not preserved.

The proliferation of QFs on a utility's system could signficantly impact the manpower (and other costs) required to disconnect and lock out QFs from the utility's system for outage clearance, construction, and maintenance purpose.

Also, a utility should review and revise, as necessary, its operation, safety, and hold tag procedures (field and dispatching manuals) in light of interconnections with QFs.

(2) Without respect to local building codes, the NEC, article 250, covers grounding and bonding of electrical installations. This article also includes specific requirements for the following:

(a) Systems, circuits, and equipment required, permitted, or not permitted to be grounded.

(b) Circuit conductor to be grounded on grounded systems.

(c) Location of grounding connection.

(d) Types and sizes of grounding and bonding conductors and electrodes.

(e) Methods of grounding and bonding.

(f) Conditions under which guards, isolation or insulation may be substituted for grounding.

(g) Connection for lightning arrestors.

(h) Grounding of dc circuits.

Grounding requirements should be in compliance with ART-250 of the NEC and any applicable local codes.

6. San Diego Gas & Electric Company, Protection and Operation Guidelines for Cogenerators and Small Power Products, Preliminary Draft submitted to California PUC, 1980.

The excerpts from the draft guidelines applicable to safety considerations are as follows:

(1) A means of disconnection under the control of utility shall be applied to all customers with parallel generation. This can be applied on either the primary or secondary circuit and accomplished with switches, load break elbows, cutouts or secondary breakers. As existing circuit design incorporates these features, additional costs should be minimal.

(2) The customer's installation must meet all applicable national, state, and local construction and safety codes.

(3) The customer shall install relaying to provide adequate protection for the following:

(a) All faults on the customer system involving phase and/or ground.

(b) Faults on the SDG&E system involving phase.

(c) Unbalanced or single phase conditions on the utility system.

(d) Prevent backfeed or start-up of the customer's generator(s) into a dead SDG&E bus.

(4) The customer shall not reconnect his generator after a protective device trip unless his system is energized from the utility source, or unless he has isolated his system from the utility. To prevent such hazardous connections, the protective devices specified by SDG&E must be provided. In addition, PCU control circuit(s) must not allow the start-up of the customer's generator(s) for dead bus conditions on the SDG&E system.

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(5) Transformers feeding customers with parallel generation shall be identified with a special tag attached to the transformer or pole. This will notify field crews of the possibility of backfeed. Incoming load data sheets should be flagged and used to initiate an order to tag poles.

7. Operating, Metering, and Protective Realying Requirements for Parallel Operation by Small Cogenerators and Power Producers, 100 kW or Less, Pacific Gas & Electric Company, Draft submitted to California PUC, September 1980.

The excerpts from this guideline regarding safety are:

(1) In all cases, a PG&E-owned, manually operated disconnect device, which can be opened for line clearances, must be provided. Usually, this will be an air switch or fused cutout on the high-voltage side near the transformer which connects the seller's generator to the PG&E system.

(2) The seller is responsible for compliance with all local, state and federal rules, regulations and codes which may be applicable.

D. CONCLUSIONS

(1) There is a general agreement that the new QFs must comply with all applicable national, state and local safety codes.

(2) Great importance is attached to the proper grounding and bonding procedures, which prevent any hazard in operating and servicing the equipment.

(3) Some utilities express the desire to be responsible for the control of the disconnecting of the PV generator, anytime. Other utilities reserve the right to ask the customer (i.e., PV power producer) to discontinue parallel operation upon request.

(4) The possibility of PV power being supplied to the neighboring utility's customers in absence of the utility's power raises the issue of the capability of a PCS feeding an island. The line-commutated inverters could not do that. The self-commutated inverters could be used, providing that they are capable of picking up the synchronization, when the utility power returns (Sometimes without advance warning). This issue needs to be investigated.

(5) Although some of the articles of the NEC and NESC may be applicable to PV systems, the code must be revised to cover various aspects of PV system installation and interconnection

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to the utility. Such revisions could help local electrical inspectors and utilities approve interconnection of PV systems and minimize the potential for inconsistencies which could result from individual interpretation of the code.

E. RECOMMENDATIONS

The National Electric Code (NEC), a volume in the National Fire Code and the bible on electrical matters for local code officials, is published every 3 years by the National Fire Protection Association (NFPA). Recognizing the ascending position of PV, the NFPA has established two ad hoc subcommittees to address code-related issues associated with photovoltaics and cogeneration and to draft recommendations for inclusion in the 1984 Code. The PV program recognizes the importance of this effort in facilitating the development of the PV industry and wishes to actively support this effort.

SECTION VII

METERING REQUIREMENTS

A. INTRODUCTION

1. Definition

Presently, the utilities use metering for:

(1) Monitoring of electrical parameters (e.g., current, voltage, frequency), for the purpose of the distribution system supervision and evaluation.

(2) Measuring of the power generated and delivered, for accounting purposes.

Energy flow is unidirectional at the distribution level. The waveform is sinusoidal; the harmonic content is minimal.

Introduction of PV generators within the utility's distribution network establishes new requirements for the additional meters to be used at the PV generator level.

2. Risk

Rotating disk type kWh and kVARh meters, as presently used by utilities, may have to be modified in the case where the amount of energy purchased and sold differs. The outgoing and incoming energy must be then measured separately by kWh (in) and kWh (out) meters. Meters must be unidirectional, i.e., the disk of the meter must be prevented from rotating in the opposite direction. If not restricted to an unidirectional registration, billing errors would occur in the systems with "payback."

It should also be recognized that a risk of error in reading the specific data exists in the presence of harmonic distortion.

3. Discussion

Presently, in the distribution sector, the only quantities monitored by the utility at the substation terminal are kW, A, V. Chart recorders are commonly used to determine if any of the above parameters have exceeded the operating limits. Inspection is periodical.

At the customer end on the residential level, only kWh is normally recorded. For larger industrial and commercial customers,

quantities such as kW, kVA, kVAR, kWh and kVARh demand, possibly linked with time-of-day (TOD) recording, may be metered.

A number of options for determining the demand (kW) and energy consumption (kWh, kVARh) levels may be encountered. These options are dictated by the structure of the agreement between the owner of PV generator and the utility as well as the operating mode of the PV power producers.

Some of the options which need to be considered are:

(1) Measuring the net amount of energy consumed or delivered by the PV generators. This would require only one kWh (out) meter. This method could only be employed if the buy-back rates by the utility were the same as the selling rates and if no time-of-day metering was used.

(2) Using separate directional watt-hour meters to measure the energy delivered by the utility and energy supplied by the PV generator. This would not impose any restriction on the buy-back rates.

(3) The same as (2), plus another meter to measure the net kVAh (in) consumed by the PV generator. This option would be employed only if the utility expressed concern about the bad power factor of PV power conditioning units.

(4) Some combination of the above options, but with time-of-day rates. This would necessitate using meters which are either internal-clock-actuated or actuated by the utility by remote control. This would be the most expensive metering option.

There could be more options in which the energy comsumption and the demand (kW or kVA), could be measured as a function of time. These would increase the complexity of the metering requirements and might not be practical.

It is important to consider the effects of wave distortion on the measurement of the different quantities. The present day induction disk-type meters are generally sensitive to only the fundamental component of real or reactive energy and could be in error if excessive wave distortion were present. In the absence of suitable meters which could function accurately under non-sinusoidal conditions, proper calibration factors must be developed for present day meters to make them compatible with PV systems.

B. REFERENCES

A number of references quoted and reviewed in DOE/ET-20356-3* deal with residential PV subsystems but are equally relevant in the case of intermediate size subsystems. They are listed again below for matter of record.

1. Fuchs, E. F., Impact of Harmonics on Home Appliances, Interim Report, performed for DOE/EES under contract DE-AC02-80RA50150.

   This report documents the effects of harmonics on single-phase watt-hour meters. The major effect of harmonics on residential appliances is to increase the power flow to these devices. This increased power flow appears as increased losses in all appliances except those which include resistive heating elements (i.e., stoves, electric frypans, etc). The watt-hour meter records part of this increased flow but not the entire amount.

Two issues are raised by the report. First, should the watt-hour meter accurately record these harmonics or, second, should the meter measure only that power which can be used by the appliances (only the fundamental). These issues are under further consideration by DOE/EES.

2. Electrical Interference to Standard Induction Watt-hour Meters, ongoing project, EPRI RP 1738.

   The study objective is to determine the response of standard watt-hour meters to various harmonics by experimental analysis. Honeywell is the project contractor.

3. Development of an Electronic Single-Phase Watt-hour Meter, ongoing Project EPRI RP 1420.

   The study objective is to develop an electronic watt-hour meter with three registers for time-of-day metering for load control and automatic meter reading by the utility. The meter would measure energy up to about the 100th harmonic. The study should be completed by the end of 1982. McGraw Edison Company is the primary contractor with Texas Instruments as the subcontractor.

*Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status, M. Hassan, J. Klein, September 1981, DOE/ET-20356-3.

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C. GUIDELINES/STANDARDS

1. *Operating, Metering, Protective Relaying for Cogenerators and Small Power Producers*, Southern California Edison Company, June 1981.

   Excerpts from this guideline relating to metering of intermediate systems are:

   (1) For installations under 200 kVA, kWh meters will be equipped with a detent to prevent reverse registration, where surplus power sales are anticipated. Edison will install additional metering so that kWh (in) and kWh (out) are separately recorded. Additional metering for kW and kVARH will be determined by the requirements of the individual installation.

   (2) For installations over 200 kVA, sales are anticipated and for all simultaneous buy and sell arrangements, Edison will install metering for kW (in), kWh (in), kW (out), kWh (out) and kVARH (in). This metering will be in the Edison interconnection facility or in the customer's switchgear, as appropriate. In addition, the customer shall also provide adequate space in the generator switchgear for Edison to install, at its option and expense, metering and/or telemetering of the generator output.

2. *Operating, Metering, and Protective Relaying Requirements for Parallel Operation by Small Cogenerators and Power Procedures 100 kW or Less*, Pacific Gas & Electric Company, Draft submitted to California PUC, September 1980.

   Excerpts from this guideline relating to metering are:

   (1) All deliveries of power between a seller and PG&E must be metered as a basis of determining payments between the parties. All meters must prevent reverse registration so that deliveries to and from the seller can be separately recorded and treated as separate transactions under the applicable rate of price schedule.

   (2) The seller will provide, subject to PG&E approval, all facilities required to accommodate any meters, which may include either standard watt-hour meters or time-of-delivery metering, depending upon the contractual agreement.

   Metering requirements for the delivery of power to PG&E will fall under two general classifications, depending upon the contractual arrangements:

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(1) Surplus sale, where only the excess of the seller's generation is delivered to the PG&E system after the seller's normal service requirements are satisfied. PG&E will provide standby and supplementary service in accordance with applicable electric tariffs on file with and authorized by the California Public Utilities Commission. An "out" meter(s) will be required to measure the seller's surplus generation which is capable of delivering power into the PG&E system. Such delivery shall be at the established service voltage.

(2) Simultaneous purchase and sale, where the entire net output of the seller's generating facility is capable of delivering power to the PG&E system while simultaneously supplying all of the seller's normal electric service requirements.

All "in" meters will be required to measure energy supplied to the seller for his generator auxiliary load when his generator is not operating and during periods of generator startup and shutdown. "Out" meter(s) will be required to measure energy delivered to the PG&E system. Such delivery shall be at the established service voltage.

3. Interconnection Facilities and Facilities for Operating in Parallel, American Public Power Association (APPA), Final Report, September 12, 1980.

Metering for billing purposes must, at the very least, measure the net amount of energy purchased from the QF or sold to the QF by the utility. (Note: Low power factor QFs may deliver kWh to the utility while simultaneously drawing kVAR from the utility).

The concept of simultaneous deliveries to the utility by QFs and to the QFs by the utility will require more complex metering installations. Metering requirements will be impacted by the physical location of the QF generation interconnection with the utility system as related to the location of the QF load connection to the utility.

The requirement to purchase from a QF does not automatically imply that the utility will sell to the QF. The utility is obligated to sell to the QF only if the QF requests such sale. Metering requirements should be dictated by and dependent upon the needs and desires of the QF, the utility and regulatory authorities. But, reasonable metering costs associated with QF generation can be imposed on the QF.

The need for precise information concerning the time of delivery of electric energy should be carefully considered. It should be recognized that electric energy and capacity may have a different value dependent on incremental deliveries, i.e., energy required

during a peak period of the day when a high running-cost generator must provide energy needs above that provided from less expensive generation during off-peak periods.

The QF and the utility can agree on purchase rates under terms and conditions which are less than the maximum allowed by FERC rules. Accordingly, certain parameters, particularly when related to capacity value, may be estimated instead of precisely determined on the basis of metered data.

4. Protection and Operation Guidelines for Co-Generation and Small Power Producers, San Diego Gas & Electric Company, Rev. 1, November 1980.

Excerpts from this guideline relating to metering of intermediate systems are:

(1) For customer generation less than 100 kW, SDG&E shall provide and install a standard watt-hour meter at the customer's facility. If the customer desires time use payments for his generation, then a Time-of-Use Meter will be installed by SDG&E with the associated cost to be borne by the customer. In addition, an operation and maintenance charge will be assessed to the customer for maintenance of the meter.

(2) For customer generation between 100 kW and 1 MW, the customer will be required to use a Time-of-Use Meter. A watt or joule-hour meter and related equipment will be installed by SDG&E with the associated cost to be borne by the customer. In addition, an operation and maintenance charge will be assessed to the customer for maintenance of the meter.

(3) When the total output of the customer's generation is greater than or equal to 1 MW, telemetering of the plant output (MW, MVAR and MWh) to the utility control center is required.

D. CONCLUSIONS

(1) Metering requirements for a PV system are a function of the utility rate structure for dispersed generators and depend upon the particular utility and the proper regulatory authorities. If the utility offers many options, the PV system owner will decide the best option based on a cost/benefit assessment.

(2) In cases where surplus power sales are anticipated, the power deliveries from and to seller will have to be separately recorded. Reverse registration by the meters must be prevented by providing the kWh meters with a detent.

(3) As PV systems will produce (or consume) real and reactive power at frequencies besides 60 Hz, it is not clear whether (or how) this component of power would or shall be measured. The commonly used induction type meters for measuring real and reactive energy are generally sensitive to only the fundamental component. Harmonic wave distortion may affect the accuracy of reading. Presently, the utilities have shown little concern for this particular issue.

E. RECOMMENDATIONS

Because the results from DOE and EPRI sponsored studies are unavailable as yet, no recommendations for further work are provided.

SECTION VIII

OPERATIONS

A. INTRODUCTION

Operational characteristics of the PCS can significantly influence the suitability of a PV-power generation system in parallel operation with an electric utility system. For example, on the unit level, the startup and shutdown procedures, as well as the ability to operate dependably within the limits of the frequency bandwidth and voltage range must be considered. On the system level, where the PV-power generator is one of many DSGs deployed, the consequences of the level and mode of PV penetration have to be assessed and means found to assure the distribution of the total generation among the various dispersed generating units (DSGs) in the most optimal way to minimize the overall cost.

This section addresses the technical and operational requirements that must be satisfied for a PCS.

B. UNIT OPERATION

1. PCS Startup

a. Definition. The concept of parallel operation of power generators with the utility is relatively easy to accomplish. The procedure of paralleling consists of making sure that:

(1) The sequence of phase rotation of two systems is the same.

(2) The frequency is the same.

(3) The amplitudes of the two voltages match.

(4) The phases of the PV and the utility voltage are the same.

That is, the interconnection of two sources is performed at the time when both sources are in synchronism.

In the case of PV generators, the initiation of the startup procedure is contingent upon the availability of the solar and utility power.

b. Risk. If the PV power is not available, paralleling must not be attempted. Connection of a de-energized PCS to the utility line may cause a reverse power flow and lead to possible component damage. Similarly, no start up of the PV power generator should be attempted if the utility line is down. An attempt to feed this line from the PV-generator could damage the PCS as well as create a safety hazard to the personnel servicing the utility line.

If both the solar power and utility power are available, the paralleling may be initiated, providing that the above listed conditions are met. If these conditions are not met, there is a possibility of the excessive currents demanded from the PCS that may cause equipment damage. Most likely the damage will, however, be prevented by protective breakers. An undesirable time delay in deployment of the power source will occur.

c. Discussion. The uninterruptable power supply (UPS) equipment was developed in the 1960's and is commercially available. The ratings of UPS are within the Class II range. The UPS equipment can be used for solar energy applications, provided that certain equipment and control logic modifications are introduced. These changes are a result of the change in the UPS source from battery to the PV array. Equipment performance specifications should address all the interface issues raised.

2. PCS Operation

a. Definition. The operation of a PCS should be as reliable as possible. Any nuisance outages should be prevented. The PCS should be able to withstand all transient perturbations originating within the utility and/or PCS without failure. Provisions for "fail-safe" shut down should be incorporated.

b. Risk. Disruption of the service due to temporary cloud coverage, temporary loss of utility power, etc., can cause PCS operational problems. As a result, a possibility of PV generator shut down or control loop PCS damage exists. Also, there exists a possibility of the PCS going unstable.

c. Discussion. Care and foresight in the design of suitable operational PCS logic will reduce the above mentioned risks. Sufficient time should be allowed for debugging the newly erected PV installations. Approval of the operational procedures should be secured from or agreed upon by the utility.

3. PV Generator Shut-down

a. Definition. Normal shut -down of the PV generator is performed regularly, when no solar energy is available. Emergency shutdown is initiated when safety of the equipment or personnel is at stake.

a. Risk. A failure to shut down the PCS when no PV power is available could cause reverse power flow from the utility that may result in damage to PCS and/or PV panel.

Equally, a failure to shut down the PCS when the utility line operates out of limits (voltage, frequency, phase unbalance), can damage the PCS.

Failure to turn off the PCS when the utility line goes down would create a hazard to the personnel servicing this line.

c. Discussion. The above outlined risks can be minimized by careful analyses of all the prevailing system conditions, functional and interface requirements, operating procedures and equipment characteristics. All of the above have to be incorporated into the system specifications and proven by test and evaluation.

C. SYSTEM OPERATIONS

The problem of power system operations can be categorized, based on the time span of interest, as shown in Figure 8-1. Each category is discussed below.

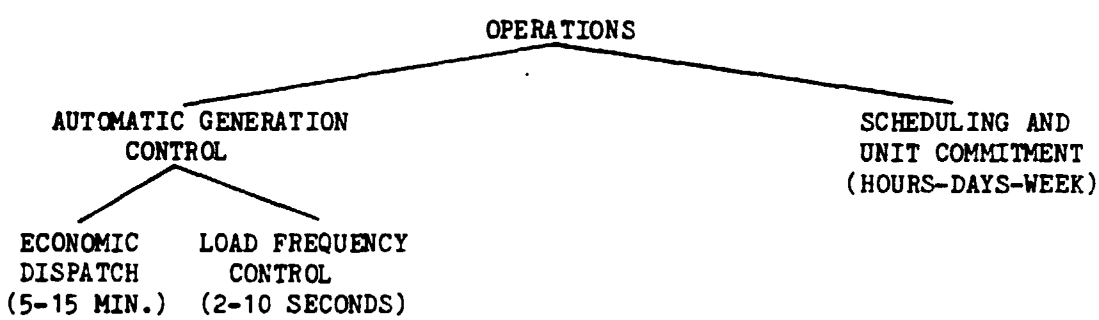

Figure 8-1. Power System Operations

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1. Automatic Generation Control

a. Definition. Automatic Generation Control (AGC) is the regulation of the output of electric generators within a prescribed geographical area to maintain the scheduled system frequency and/or the established interchange of power with other areas within predetermined limits.

Even if one PV system of intermediate type may not have significant effect on AGC, increased penetration will start exerting a definite impact on AGC.

b. Risk. With a large penetration of PV systems, fluctuations in PV output could cause excessive swings in system frequency unless proper control action is initiated.

c. Discussion. The load on a utility power system fluctuates constantly and the generation must be ramped up and down to meet the ever changing load demands. This implies that utilities should have enough generating units on-line that are capable of load following (changing their generations to meet the variable load demand). Any change in system load results in a momentary change in system frequency. The magnitude and duration of this change of frequency is dependent on many factors such as the inertia of the system, magnitude of the disturbance, and the control action employed, etc. It is highly important that these fluctations which would result in malfunctions of frequency sensitive devices such as clocks, relays, etc., be kept to a minimum.

Because a PV plant output varies continuously (usually a smooth variation, but sometimes a severe fluctuation because of the weather pattern) it will have a direct impact on the Automatic Generation Control requirements. The greater the PV penetration in a utility system, the greater control requirements (such as more units capable of load following) will be. This will certainly have a cost impact as well as an impact on the performance of the system. This could limit the maximum penetration of PV sources on any given system, but is not expected to be a real factor until a significant amount of PV generation compared to total system generation is used.

2. Economic Dispatch

a. Definition. Economic Dispatch Control (EDC) is the distribution of generation requirements among alternative sources for optimum economy.

c. Discussion. It seems unlikely that this issue will pose any major problems to the introduction of PV other than modifications in control requirements. As PV systems have essentially zero incremental costs, they should be dispatched first. The conventional units will then be dispatched economically to serve the remaining load.

3. Scheduling and Unit Commitment

a. Definition. Scheduling is the commitment of various generating units a few hours to a day in advance to meet the expected load, usually based on economic considerations. Generally, unit commitment covers a broader period (up to a couple of weeks) and is usually based on the expected availability of various units.

b. Risk. As the amount of PV generation cannot be accurately predicted in advance, some allowance in terms of increased spinning reserve or standby generation may have to be made.

c. Discussion. Determination of the generating capacity to be operated for a given total load by the utility is based on the following:

(1) Economic evaluation.

(2) Reserve requirements.

(3) Stability limitations.

(4) Voltage limitations.

(5) Ability to pick up load quickly.

(6) Available units.

The uncertainty associated with PV generation will impact all these considerations in varying proportions. The impact will be a direct function of PV penetration: the greater the penetration, the greater the impact will be. The impact could probably be lessened by a real-time weather monitoring system which could warn the system operator ahead of the time of impending weather conditions.

D. REFERENCES

A number of references quoted and reviewed in the DOE/ET-20356-3* deal with the residential PV subsystems and are equally relevant in the case of intermediate size subsystems. They are listed below for matter of record and are supplemented by a set of new references.

1. Kirchmayer, Leon K., Economic Operation of Power Systemms, John Wiley & Sons, New York, 1958.

This book presents theory and practical applications involved in determining the economic operation of a power system. It develops the necessary circuit and mathematical techniques required in addition to describing the important role that computers can play

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in improving power system performance. A large part of the book is devoted to methods of calculating transmission line losses through transmission-loss formulas.

The metho_s in this book have been widely applied by electric utilities in the United States and Canada, resulting in significant sa''ngs in fuel costs.

2. Cohn, Nathan, Control of Generation and Power Flow on Interconnected Systems.

   This is one of a few books available on the subject. It discusses the theory, advantages, and responsibilities of different companies interconnecting to form power pools. The governor characteristics and their role in Automatic Generation Control (AGC) are discussed. Area regulation and regulation as a function of bias are discussed in depth. The theory of economic dispatch is briefly covered. Methods for determining transmission losses are described. Block diagrams of control systems to achieve economic dispatch, area regulation, etc., are also discussed.

3. Lee, Stephen, and Yamayee, Zia, Load-Following and Spinning-Reserve Penalties for Intermittent Generation, IEEE Paper No. 80 SM 582-7, IEEE-PES Summer Power Meeting, July 1980.

   In this study, it is demonstrated that the increased requirements can completely eliminate the usual energy and capacity credits because of PV systems. At lower levels, the increase in load-following and spinning-reserve is fairly linear with some energy and capacity credits found. The study, however, did not use a method which chose the mix optimally; screening curves were used. There are also some questions on the probabilistic dispatching scheme.

4. Schweppe, Fred C., Economic Scheduling of Distributed Storage and Generation, not published.

   This is an excellent first step toward determining the effects of intermittent generation upon the strategy used to dispatch units. It assumes that a unit commitment and maintenance schedule have already been developed for the coming week. Once done, the study states three major findings:

   (1) The effect of stochastic local variations in microweather patterns (cloud cover, wind gusts) on small solar and wind units can be ignored at the central dispatching office, independent of the number of units. This result is based on

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*Distributed Photovoltaic Systems: Utility Interface Issues and Their Present Status, M. Hassan, J. Klein, September 1981, DOE/ET-20356-3.

the assumption that the variation in the weather at this small local level is statistically independent over the geographical area served by the central dispatching office.

(2) The effect of global variation in microweather patterns (storm fronts) on solar and wind units is very important at the central dispatching office unless the number of units is small. In this case, the weather variations are dependent upon each other and, thus, affect the result.

(3) Highly accurate scheduling is not required/justified for small dispersed units. This is based on a wide distribution in system lambda so that the optimum scheduling is obvious and the fact that a small intermittent unit is involved so that a small amount of energy is injected into the system.

5. Fegan, George, and Percival, C. David, Problem in the Integration of Intermittent Sources into Utility Production Costing Models, No. SERI/TP-351-546.

The intermittent generation source, a source over which the utility dispatcher has minimal control with regard to power availability, presents serious problems. The problems are separated into those renewable resources which are correlated to the demand and those which appear to act independently of demand. Approaches to solutions are explored.

New References:

6. Addiss R. R. and Lawson P. A., A 194 kW Solar Photovoltaic Flat Panel Power System for the Combined Beverly High School/C. H. Patten Vocational High School, Beverly, Mass., Final Technical Report, June 1980, DOE/ET/23064-1.

For a flat-plate system, it is desirable to integrate all control functions within the PCS. An inverter package was sought that could satisfy all power conditioning and control requirements and be deliverable within the construction timetable restrictions. The major criteria for the inverter are defined as follows:

(1) The inverter output or parallel outputs of inverters must provide three-phase, 60 Hz, balanced power with a waveform deviation factor of less than 0.1 and a power factor not less than 0.80 from one-quarter of full output to full output, when connected to a utility grid system. The power quality requirements were imposed both to ensure utility acceptance and to ensure no detrimental interaction between inverters and building loads.

(2) The inverter input must contain peak power tracking circuitry that extracts the maximum amount of power from the array subfields. It must maintain this control over all steady-state and transient insolation conditions and over the full array peak power voltage range. The total width of this range is 35 percent of the nominal voltage.

(3) Efficiency must be competitive with other available inverters at all input power levels. Power handling components must be sized and cooled adequately to ensure long life.

(4) The inverter must contain the following additional controls: automatic startup and shutdown and automatic disconnect from the ac line in the event of a phase-to-ground or phase-to-phase short circuit, sustained line over or under voltage, reverse power flow, and loss of utility service (to protect utility repair personnel from wire hazards).

(5) Alarms must be included to indicate fault conditions.

(6) Provisions for manual override of the peak power tracker control, any other necessary self-protection circuits and controls, and meters and status lights adequate to diagnose operational problems shall be included.

7. <u>Airport Solar Photovoltaic Concentrator Project Specification</u> (ASPCP), Motorola Inc. Document. No., Date. (Martin Marietta is currently prime contractor.)

The purpose of the power conditioning equipment is to transform the dc energy generated by a large photovoltaic concentrating solar array field to a standard, usable form of ac power. This solar energy recovery system is to be installed at Sky Harbor International Airport in Phoenix, Arizona, and is to be funded by the U.S. Department of Energy (DOE) as an experimental demonstration of a moderate-sized, photovoltaic, solar energy recovery system. The Arizona Public Service Co. (APS) will be the prime contractor and system operator for this experimental system.

The following is the abstract of the stipulated requirements for proper plant operation:

<u>Parallel with Utility</u> The ASPCP will always operate in parallel with the utility grid. Power transients generated by the ASPCP due to rapid shutdown at maximum power will be absorbed by the utility. The inverter shall be disconnected from the utility and the array open-circuited during periods of no sunlight or during daytime shutdown. If the utility fails, the ASPCP will shut down and remain off until utility power returns.

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Peak Power Tracking The inverter shall have suitable logic to sense the array output power and change the inverter load to the array to maximize array power. This peak power tracking (PPT) feature shall control the inverter during parallel operation with the utility.

Startup The power conditioning system (inverter) shall have an automatic startup mode and a manual startup mode. In the automatic mode, startup shall occur when there is sufficient array power to compensate for the standing losses of the inverter to supply a predetermined minimum amount of power to the utility and when the inverter input voltage is within an acceptable range. Manual startup shall override automatic operation. All switching of power shall be done by remote control and switch status shall be provided (except manual disconnect switches). Startup shall always close the circuit breaker in the APS which is on the load (terminal) side of the transmission line.

Shutdown The inverter must always operate synchronously with the utility grid. Failure of the utility when the inverter is operating in parallel with the utility shall cause the inverter to shut down. The PCS (inverter) shall have an automatic shut down mode and a manual shutdown mode. Manual shutdown shall override automatic operation. In the automatic mode, shutdown can occur due to (1) low array power as at the end of the day, or (2) a system or inverter fault. Shut down due to low array power shall be a delayed shutdown, such that the power output of the solar array field must remain below inverter standing losses from 0-10 minutes (adjustable) before shutdown is initiated. In this way, unnecessary shutdown due to rapidly changing cloud cover is reduced. There should be some hysteresis between the automatic startup and shutdown power levels. Automatic shutdown, due to a fault in the system, shall not be delayed but shall occur nearly instantaneously; i.e., inverter power shall not first be reduced. Shutdown shall always open the circuit breaker which is on the load (terminal) side of the transmission line. The array power level required for automatic shutdown is yet to be decided but will be enough to compensate for the standing losses of the inverter.

Fault Protection Fault protection circuits shall prevent damage to the inverter and to the photovoltaic power system. They shall sound an alarm and provide fault status for data system requirements. The inverter shall contain the necessary fault protection circuitry to shut down and recycle the inverter through one restart cycle. Recycle and restart shall be automatic for momentary faults and manual for faults requiring servicing such as a blown fuse.

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Load Sharing Load sharing between the utility grid and the photovoltaic power system shall be automatically accomplished by inverter logic circuits internal to the inverter which control both phase and amplitude of the inverter output. The peak power tracking shall primarily control the flow of power through the inverter although manual control of power shall be available.

Manual Control Manual control of the ASPCP power conditioning equipment shall be provided and shall include control for (1) startup, (2) shutdown, and (3) power flow through the inverter. Manual control of the inverter output power shall also be provided to facilitate plotting the array I-V characteristic. The range of manual control of the inverter input voltage shall be negotiated after contract award. The necessary meters for manual control shall be provided on the inverter console.

E. GUIDELINES/STANDARDS

No guidelines or standards could be located on the issues related to system operations. Guidelines related to the single PCS are becomming available. Two documents are referenced below.

1. Guidelines for Operating, Metering and Protective Relaying for Cogeneration and Small Power Procedures, Southern California Edison (SCE) Company, June, 1981.

   These guidelines state the minimum requirements for safe and effective operation of customer-owned generation on the Edison system. Customers and Edison personnel may be guided by this document when planning installations of customer-owned generation. It is emphasized that these requirements are general and may not cover all details in specific cases. The customer should discuss project plans with Edison before purchasing or installing equipment.

   For the purpose of simplicity, the term "customer" will be used in this guideline to refer to both cogenerators and small power producers, even though they may not actually be customers for Edison's electric service.

   The guidelines review the general and specific requirements. Distinction is made between systems below and over 200 kVA.

   Protection may be provided by Edison or by customer.

   Some selected wishes of SCE are that:

   (1) The customer shall discontinue parallel operation when requested by Edison.

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(2) For generation installations less than 200 kVA, the utility will supply the VAR requirements at no cost to customer. For installations over 200 kVA, the installation of PF capacitors will be at the expense of the generating facility.

(3) Paralleling of two sources will never be attempted while the customer's synchronizing equipment is inoperative.

(4) Customer shall be responsible for: (a) detecting a voltage and frequency out-of-limit and initiating the shutdown of PV-source; (b) preventing reparalleling of the PV-source after incident until the service voltage returns to normal magnitude and phase sequence.

2. American Public Power Association (APPA) <u>Interconnection Facilities and Facilities for Operating in Parallel</u>, Small Power Production and Cogeneration Task Force, Final Report September, 1980.

This guideline was prepared by a five-member subcommittee of the APPA Cogeneration Task Force. It is primarily intended to provide an overview, with some detail, of the technical aspects of interconnecting and operating in parallel with cogeneration and small power production facilities, as required under the final rule issued by the Federal Energy Regulatory Commission (FERC) on February 19, 1980, regarding the implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978.

The information may be used as a tool to commence analysis of any proposed interconnected operations with a qualifying facility (QF), but it should not be referenced to limit either the scope of an analysis or the number of factors that need to be analyzed.

Some technical considerations of interconnected operations with QFs are not addressed in this document. These include, for example, the impacts of increasing numbers of QFs connected to a single or multiple circuit(s) of a utility and the impacts of more than one QF connected in series with a utility.

This documentation is a starting point to initiate analyses of interconnected operations with a QF. Hopefully, it will stimulate one's thought processes to consider aspects, including solutions, not addressed or only indirectly addressed within it.

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F. CONCLUSIONS

(1) At this time, only a small number of intermediate-size, Category II, PV installations are functioning and only limited experience has been gained regarding all operational interface issues.

(2) The operational recommendations for single PV sources interated into the utility grid are slowly emerging.

(3) The introduction of PV systems into the utility grid is not expected to have a substantial impact on system operations until the penetration is quite high. This is probably the main reason for the absence of sufficient, relevant literature on the subject.

(4) The impact on system operations will probably be an economical rather than a technical concern. Any technical impacts will probably be limited to investigating better weather prediction techniques, better control algorithms, and better communications alternatives.

G. RECOMMENDATIONS

Detailed studies need to be performed to analyze the operational issues associated with Category II-size installations. The larger size requires a more detailed analysis to determine if more complex controls are cost effective. To do this, valid models for the three-phase installation must be formed. The status of the recommended issues is shown in Table 8-1.

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Table 8-1. Status of Category II Operational Issues

Problem Issues	Present Status	Future Status
Single PV Models (Stochastic)	B	A
Aggregate PV Models (Stochasic)	D	D
Effects on AGC, ED	C	C
Effects on Scheduling and Unit Commitment	C	C

A The issue is completely resolved or can be resolved when based on available knowledge.

B Much is known or documented, but the issue is not totally resolved.

C Very little is known or documented.

D Nothing is known or documented.

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SECTION IX

DISTRIBUTION SYSTEM PLANNING AND DESIGN

A. INTRODUCTION

1. Definition

Modifications are needed in the distribution system planning and design process of conventional distribution systems so that the integration of PV systems can be accommodated successfully.

2. Risk

(1) By not planning for consideration of PV, the integration of PV must occur through actions in the design phase only. Thus, the lead time for utility design is shortened with fewer options available to enable the integration to occur successfully.

(2) By not considering PV in design efforts in advance of need (such efforts may be triggered by an entrepreneur installing PV), the early and highly visible projects may accidentally demonstrate that PV is more trouble than it is worth.

3. Discussion

The lack of consideration of large penetration of PV in the planning and design of distribution systems may lead to inadequate resolutions of the other issues. For example, protection and safety issues may be considered based on present distribution system configurations and practices. But if, in fact, large local penetration of PV logically calls for basic changes in the distribution system, then protection and safety issues were considered for the wrong systems. The way in which some of the other issues might be resolved (such as harmonics, VARs) could include changes in the distribution system. Such changes should be part of an early distribution system planning and design concept effort. If not, then the validity of conclusions will be suspect.

B. REFERENCES

1. Expansion Planning for Distribution Networks, ongoing DOE/EES contract with Carnegie Mellon University.

The task objective is to develop methods to plan the expansion of networks with conventional and emerging energy technologies, including dispersed generation and storage devices.

A multi-objective model to optimize the operations of radial networks with dispersed storage and generation devices was developed. The optimization is in terms of two conflicting attributes: (1) operating cost and (2) load curtailment. The model is solved with a network version of the generalized transportation algorithm that uses multiple arcs between nodes and lower and upper bounding. A commercial code was implemented which solves large problems efficiently. The solution provides guidance for day-to-day operations. It can also be adapted to provide design and expansion information through sensitivity analyses of the configuration studied.

Models were also developed for predicting the effects of energy management technologies on two important system attributes: (1) production cost and, (2) the load shape seen by central generation. The models can include arbitrary mixes of central generation, dispersed generation, central storage, and dispersed storage.

2. <u>Electric Power Distribution System Planning and Design with Dispersed Storage and Generation (DSG) and Distribution Automation and Control (DAC)</u>, RFP DEDS-19-01, by Oak Ridge National Lab for the Department of Energy.

The overall thrust of this activity is to carefully examine the distribution planning and design process in light of DAC and how DAC might facilitate the integration of DSG and load management into the electric distribution system.

The specific tasks under this investigation are:

(1) Perform conventional planning and design of a particular utility system after formulating a planning and design scenario.

(2) Describe the modification in conventional distribution planning and design process required with DAC. Describe the DAC functions and why they are likely candidates for that particular system. Perform an analysis of the technical and economic impacts of DAC. The DAC functions to be considered are outage reporting, system reconfigurations, remote equipment operation, remote meter reading and VAR control.

(3) Examine the changes in the planning and design process when DAC and load management are used, in addition to conventional distribution techniques, to help solve the scenario formulated earlier. The load management options to be considered are customer thermal energy storage, direct and

indirect control of customer loads, conservation and TOD rates, as they affect the distribution palnning and design process.

(4) Examine the changes in the distribution planning and design process when dispersed generation in low penetration exists on the utility system. Customer-owned and utility-owned dispersed generation will be considered separately and then compared. A low penetration is defined as 2% or less of the best utility system capacity under study unless reasons are shown that it should be otherwise.

(5) The same as (4) but with a high penetration of DSG, DAC, and load management. A high penetration of dispersed generation is defined as between 10 and 20% unless reasons are shown that it should be otherwise.

(6) The final task is to evaluate, compare, and summarize the cases studied to show the effectiveness of DAC, DAC and load management, and low and high penetrations of dispersed generation on distribution system short-term planning. Particular attention should be paid to the design criteria and problems faced by the utility such as line and equipment loadings, voltage control, harmonics, power factor, phase balance, losses, reliability, etc., if and where they apply. Distribution design guidelines should be provided for the following cases:

   (a) Modified design with DAC.

   (b) Modified design with DAC and load management.

   (c) Modified design for low and high penetrations of dispersed generation.

3. <u>Impacts of Dispersed Storage and Generation in Electric Distribution Systems</u>, Final Report, System Control Inc. for the U.S. Department of Energy under Contract #EY-76-C-03-1214, July 1979.

The study objective was to determine the benefits, if any, of DSGs on utility distribution systems by reducing capacity requirements, increasing reliability, and lowering losses. Alternate DSG technologies studied include dispersed supply management devices placed on the utility side of the meter (such as solar energy generation, battery storage, and fuel cells) and use management devices placed on the customer's side of the meters (such as cogeneration and storage space conditioning).

The methodology included detailed simulations of distribution system expansion planning with and without DSGs, using a consistent set of planning criteria. Models of alternate DSG

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operating controls were developed to satisfy distribution and/or bulk-supply system needs. The incremental effects on the bulk-supply system production costs and capacity requirements were calculated. Detailed planning simulations in the methodology were used to model important distinct distribution system characteristics.

The overall study conclusions were:

(1) To realize distribution capacity and reliability benefits, supply-side DSG may be operated in a manner departing from bulk-supply system economic dispatch principles. Potentially higher production costs and DSG capital costs may be incurred, in addition to increased backup bulk-supply capacity requirements for energy-limited, dispersed storage devices.

(2) The overall cost benefits of DSG technologies are highly site-dependent. Substation placement is generally more favorable than placement along the circuits.

(3) The overall benefit decreases over time with increasing dispersed utility-side storage. Total benefits improve over time with increased penetration of dispersed utility-side generation.

(4) Utility-side dispersed generation tends to attain a greater overall benefit than dispersed storage.

(5) The introduction of DSG into the electric distribution system will complicate present planning and operating practices. Present distribution practices relying on established planning guidelines and engineering judgment may prove insufficient because this experience was accumulated for systems without DSG. Planning and operation of DSG may require close coordination between bulk supply and distribution system planning.

Overall, the thrust of the study is an economic evaluation of DSGs rather than concern about how the planning problem will be modified by their inclusion. The study conclusion arrived at in (5) is precisely the issue that must be resolved for distributed PV systems.

4. Impact of Dispersed Solar and Wind Systems of Electrical Distribution Planning and Operation, Final Report by SCI for Oak Ridge National Lab., ORNL-SUB-7662-1, February 1981.

This study examined the technical and economic impacts of dispersing solar and wind (DSW) generation devices within the distribution system. A DSW operation model was developed to help determine the dependable capacity of fluctuating solar

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photovoltaic and wind generation as part of the distribution planning process. Specific case studies using distribution system data and renewable resource data for Southern California Edison Company and Consumers Power Company were analyzed to gain insights into the effects of interconnecting DSW devices.

Although results were case-specific and applicable only to distribution systems studies, some important general conclusions are made. The DSW devices offered some distribution investment savings, depending on their availability during peak loads. For a summer-peaking utility, for example, dispersing photovoltaic systems are more likely to defer distribution capital investments than dispersing wind systems. Dispersing storage devices to increase DSW's dependable capacity for distribution system needs is not economically attractive. Spatial diversity among dispersed wind generators may improve their dependable capacity at the bulk generation level, but for the relatively small service area of a distribution system, this improvement is insignificant. Substation placement of DSW and storage devices is more cost-effective than feeder or customer placement.

C. GUIDELINES/STANDARDS

No guidelines or standards exist on this particular issue.

D. CONCLUSIONS

Many ongoing efforts are identified in the area of distribution planning and design with dispersed storage and generation including PV. All these efforts are sponsored by the DOE/EES. The results generated by these studies, once completed, would help resolve this particular issue. The impact of recent DOE budget changes on DOE/EES efforts is not yet known. It is quite probable that the expectations and plans will not be realized in full.

E. RECOMMENDATIONS

No recommendations for further work are provided at this time in the area of distribution planning and design.

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APPENDIX C

LIST OF ORGANIZATIONS INVOLVED IN UTILITY INTERFACE ACTIVITIES

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(1) State Public Utility Commissions, e.g., State of California, etc.

(2) American National Standards Institute, e.g., Steering Committee on Solar Energy Standards Development.

(3) Institute of Electrical and Electronic Engineers (IEEE).

(a) Power Engineering Society

1) Working group to investigate consumer-owned sources of generation 1000 kVA or less.

2) Working group on harmonics.

3) Working group on lightning protection of distribution lines.

4) Task group on long-range distribution planning.

5) Working group on long-range system planning.

6) Working group to study wave distortions in consumers interconnections.

7) Working group on AC-DC converter station harmonics.

8) Working group to study effect of harmonics on meters.

(b) Industry Application Society

1) Harmonics and reactive compensation subcommittee.

2) Thyristor Converters for Motor Drives - Packaged Drive Standards Subcommittee.

3) Wave Shape Distortion Working Group.

(c) Standards Coordination Committee on Photovoltaics

1) Photovoltaics System Subcommittee on Standards for Terrestrial Photovoltaic Systems-Utility Interface Working Group.

2) Photovoltaics Array Subcommittee.

3) Photovoltaics Power Conditioning Subcommittee.

4) Photovoltaic Storage Subcommittee.

(4) Department of Energy (DOE) including Division of Electric Energy Systems (EES).

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(5) Electric Power Research Institute (EPRI).

(6) American Public Power Association (APPA).

(7) National Rural Electric Cooperative Association (NRECA).

(8) Underwriters Laboratory (UL).

(9) Arizona State University Laboratory on Utility Interface.

(10) Various Utilities.